COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

ELECTRICITY COMMITTEE

Implementation of Renewables Portfolio Standard Legislation (Public Utilities Code Section 381, 183.5, 399.11 through 399.15, and 445 [SB 1038], [SB 1078]	Docket No. 03-RPS-1078 RPS Proceeding
and	
Preparation of the Integrated Energy Policy Report	Docket No. 06-IEP-1 2007 Integrated Energy Policy Report

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, JUNE 27, 2006

9:34 p.m.

Reported By:

Christopher Loverro

Contract No. 150-04-002

COMMITTEE MEMBERS PRESENT

John Geesman, Commissioner

ALSO PRESENT

Joseph Desmond
Undersecretary of Energy Affairs

John Bohn, Commissioner
California Public Utilities Commission

Eric Saltmarsh, Executive Director
Electricity Oversight Board

PANEL MEMBERS

Panel 1 Members

Steve Zaminski, Moderator
Starwood Energy Group
Kevin McSpadden, Milbank, Tweed, Hadley & McCoy
Thomas King, US Renewables Group
Joe Greco, Caithness, Western Development
John Seymour, Florida power & Light Energy
John Tormey, Constellation Generation
Tom Lumsden, FTI Consulting
Tom French, CalISO
Fong Wan, PG&E
Pedro Pizarro, Southern California Edison
Teresa Farrelly, San Diego Gas and Electric

Panel 2 Members

Gary Ackerman, Moderator
Western Trading Forum
Kevin McSpadden, Milbank, Tweed, Hadley & McCoy
John Buehler, Energy Investors Fund
John Flory, North American Energy Credit and Clearing Corp.
Joe Greco, Caithness, Western Development
John Seymour, FPL Energy
John Tormey, Constellation Generation
Fong Wan, PG&E
Bobby Little, SCE
Lad Lorenz, SoCal Gas and SDG&E
Russell Read, CalPERS, CIO

Panel 2 Members - continued

Curtis Kebler, Goldman Sachs
Partho Ghosh, Marsh Alternative Risk Solutions, SVP-Financial
Steve Kelly
Pedro Pizarro, Southern California Edison

I N D E X

I N D E X

P R O C E E D I N G S

9:34 a.m.

UNDERSECRETARY DESMOND: Good morning.

I don't hear a good morning back.

(Laughter.)

UNDERSECRETARY DESMOND: It is a good morning.

Well, I'd like to welcome everyone here today to this workshop on lowering the effective cost of capital for generation projects. And this is particularly of interest since quite some time ago, I want to say maybe about six, seven months ago, Commissioner Geesman and I were both approached in a number of different ways raising the issue of how are the credit policies affecting California's cost of generation, and specifically with credit policies that impact the cost of renewable energy.

So we have quite a content filled agenda today with a series of excellent speakers and excellent panelists. We also are doing this presentation online via WEBEX, so let me walk through just some housekeeping items first.

For those of you not familiar with this building, the closest restrooms are located on the first floor. You go right out this door, on either side you'll find those located. There is a snack bar on the second floor under the white awning, and in the event of an emergency and the building is evacuated, please follow our employees to the appropriate exits. They'll be the first ones out the door.

We will reconvene -- like an airlines flight, isn't it. We will reconvene at Roosevelt Park located diagonally across the street from this building. Please proceed calmly and quickly, and again, following the employees with whom you are meeting to safely exit the building.

A note to the WEBEX participants, which is the Energy Commission's online meeting service. Although the chat feature is available for WEBEX participants to use among themselves, the meeting's presenters will not be responding to chat during the presentations. All the workshop presentations are relatively short, so we would like to hold questions until after each presentation. WEBEX participants will be muted during the presentations but can ask questions and provide comments by clicking on the raise hand button on your computer screen when the presentation is finished. You can then be un-muted in turn by the moderator.

It is important to speak into the microphones when addressing the workshop. You will not be heard by participants or the court reporter if you do not use a microphone. And please be sure to identify yourself as well as your organization.

Please be aware that the workshop's audio and presenters WEBEX computer activity will be recorded, and to the extent they were available, copies of panel members' biographies and workshop presentations are available in the table, on the table in the foyer.

Today's workshop presentations, WEBEX recording, and a transcript of the proceedings will be made available after the workshop on the Energy Commission's Website, which is www.energy.ca.gov, and you'll just navigate to the links, and we'll also provide that. And there is a handout in the foyer with the Web address, and it will also be repeated at the end of today's workshop.

Written comments on workshop topics can either be hand-delivered, mailed, or e-mailed to the Energy Commission's docket office. They must be submitted by 5:00 p.m. on July 11th, 2006. And please consult the original workshop notice for details on how to properly submit comments.

And then, lastly, as a housekeeping note, a summary report of the workshop will be prepared after the comment deadline. Similar to part workshop materials, the report will be made available in hard copy and electronic formats, and you will be notified of its availability.

So before beginning, I'd like to acknowledge and provide a special thanks today to the panel moderators, Steve Zaminski from Starwood Capital, and Gary Ackerman, Western Power and Trading Forum, as well as all the members, Commissioner Geesman. We have to his left his assistant, Melissa. Eric Saltmarsh, from the Electricity Oversight Board. Newly-installed Commissioner Jeff Byron. We have his assistant, Kevin Kennedy, as well as CPUC Commissioner John Bohn.

COMMISSIONER GEESMAN: I just thank Chuck Najarian for doing the staff work to assemble today's presentation, and thank all the panelists for your participation here today.

UNDERSECRETARY DESMOND: A few other notes that we have here today. Rick O'Connell will be presenting the credit requirements survey, which I think we'll find very interesting. Steve St. Marie has also provided some support, Steven Kelly, in organizing his members, who has also raised this issue in the past and I know is looking forward to today's discussion. Les Guliassi and Manuel Alvarez for their help in the investor owned utilities, and in addition, as Commissioner Geesman has indicated, Chuck Najarian has been instrumental in organizing and pulling together the overall agenda. His staff folks here, Madeleine Meade, Tony Goncalves, Heather Raitt, Drake Johnson, Larry Baird, Steve Bonta, and Jerome Lee. And I believe I have touched on everyone.

So before beginning, I'll turn this over to see if any of the fellow folks here on the dais would be interested in making some comments. Commissioner Geesman?

COMMISSIONER GEESMAN: No.

UNDERSECRETARY DESMOND: Mr. Saltmarsh.

MR. SALTMARSH: No. I, just by way of introduction, this is my second week on the job, and I'm very glad to be here. But I, I'll save my remarks for the first business meeting.

I'd like to very much thank our panel for being here today. I'll tell you, when I first heard about this meeting last week I was extremely excited about it. This is something that, that we really need to understand much more, and I appreciate your all being here today. Thank you.

UNDERSECRETARY DESMOND: Commissioner Bohn? No.

Okay. Well, with that, why don't we turn to our first presentation, and that will be Rick O'Connell -- let me just come to the agenda -- which is the review of current credit requirements. And this is work that we've been doing now under the direction of the California Energy Commission, and he'll be presenting this information.

And I'd also like to acknowledge and welcome everyone who is available and logged on via the WEBEX, as well.

Mr. O'Connell.

MR. O'CONNELL: Great, thanks, Mr. Desmond.

Hi, I'm Rick O'Connell from Black and

Veatch. I'm a contractor to the Energy Commission, and the Energy Commission asked me to, to sort of put together a report which is available outside, as well as this presentation. The hard copy of the presentation is a little bit slightly more extensive. In the interest of time, and due to the fact that I've had several cups of coffee, I'm going to move very quickly.

There's a -- as, as everybody knows, there's an enormous amount of information here, and it's, it's going to be hard to sort of cover it all in depth, but I think the idea of me starting this off here was just to give everyone kind of a background idea of what exactly credit requirements are, what they are in California, and, and also, I also looked at some other states around the west to just sort of do a comparison.

And just so people know, I'm slightly biased. I've worked for the RPS office here at the Energy Commission, so my bias is slightly towards renewables, and my knowledge base, so you're going to have to forgive me in advance.

So I'm going to just really introduce what credit requirements are. I think the utilities are going to speak later about exactly why they want to do credit requirements, so I'm not going to say what they are. But generally, it's just, you know, money, some information, and some kind of collateral that allows a developer to bid into an RFO, enter into a PPA, and then maintain good standing under that PPA.

And, and what I'm going to focus on is really just the credit requirements demanded of the developer by the utility. I'm not going to look at all, at, you know, obviously there's, there's times when the utility is going to have to post collateral, and I'm not going to really touch on that at all.

And so these are the, these are the credit requirements that we look at. You know, bid deposits, not technically credit requirements, but everyone seems to lump them in with the category of credit requirements. Financial information, development security, and operating collateral. And I'm going to go through all four of these quickly.

And I think I'll, I think I'll let the utilities sort of talk about why they have credit requirements, but it's really just to make the utility whole in, in case of, in case of breach or default by the, by the contractor.

One of the exciting things about putting together this presentation is there's absolutely no way you can make any pictures about credit requirements, so it's very easy, very easy to make this.

I think a really important point that I learned while in the, in the process of doing that, and I really thank you all, there's a lot of people in this room that helped me put all this work together, is the different types of collateral that are available. You know, most people obviously aren't going to use cash. You don't want to tie up equity in posting collateral that you could put to work building your projects, so most people use an instrument like a letter of credit. And the fees for a letter of credit are obviously going to range in, in a broad range, depending on the creditworthiness of you, as a developer.

But the important things are also the secondary effects of, of getting a letter of credit. So it's not just the check that you have to write to the bank to get that letter of credit, that's actually when you get a letter of credit it's going to reduce your overall borrowing capacity for the project. It's going to reduce the, you know, the check you have to write to the bank, it's going to reduce the cash flow available for financing.

So there are these secondary effects of getting collateral that I think are really important and are, and are hard to quantify because it's going to be really different on a project by project basis, depending on the creditworthiness of your developer, of their parent company, their relationship with the bank, et cetera. So these are really hard to quantify, and I had to, like, use a lot of rules of thumbs in the, in the data that you'll see later.

And then a lot of times there's what we call a collateral threshold, which is based on your, based on your credit rating you may not have to put up. If you're required to put up 20 million in collateral and you have a collateral threshold of ten, you actually only have, you're only going to have to post ten million. Once again, that's going to benefit larger developers.

So you can, you can see this, this list in your print-out, but I looked at 18 RFOs across

California, IOUs, both renewable and non-renewable. I looked at SMUD and LADWP, and SCPPA here in California. And then I looked at Nevada Power, PacifiCorp, Xcel and APS, both renewable and non-renewable. So I, I tried to get a, tried to get a big picture of credit requirements around the west so we could sort of compare and contrast and say hey, what's going on in California. Is it, quote/unquote, typical or not typical.

And then, to make, to make things easy to understand, instead of just sort of talking about credit requirements as $3 a kilowatt or $5 a megawatt hour, I actually created these two proxy, you know, putative projects, that both have roughly the same annual generation of about 300,000 megawatt hours, and that they have different characteristics, you know, different prices, different capacity factors, and obviously, different nameplate capacities.

So this gives -- so you can actually see as, as we go through each of the credit requirements, you can say okay, what does this mean for me if I'm a developer building a 40 megawatt geothermal project, what kind of -- what, what numbers are we actually talking about. And,

and I think these are all generally reasonable assumptions. Obviously, you know, market's going to change, but for now they're roughly reasonable assumptions.

So we start quickly talking about bid deposits. Like I said before, these aren't really credit requirements. These are either due at the time you submit the proposal to the utility, which is, you know, like a proposal, which is called a proposal fee or proposal security, or when the project is chosen for a short list. The recent PUC decision sort of urged California utilities to use $3 a kilowatt due at short-list, and, and I think both PG&E and SCE are now using it on the 2006. SDG&E still seems to be using no, but actually I just looked at their report and it seems like maybe they will be using $3 a kilowatt.

So this is what, what bid deposits look like across different renewable solicitations. You can see LADWP is quite higher at $5 a megawatt hour. I believe most developers refuse to pay that, though that's, I don't think that's necessarily public knowledge. Whereas Xcel uses a, uses sort of a flat fee of $2,000, and I think it's, it's lower. If it's under ten megawatts it's $500, and between 10 and 20 it's a thousand.

For non-renewables, there's, there's, once again, also different, you know, Xcel uses a flat fee, APS uses a flat see. PG&E uses $5 a kilowatt. That actually goes up to $10 a kilowatt when the contract is sent to the, sent to the PUC. I want to point out something here which is going to be important later on, is that, you know, obviously, different all source, some, some all source are, if those are for new generation, such as the PG&E 2005, some all source are, those are fort sort of more short-term marketing such as the SCE 2005, so that's why we're going to see some pretty significant differences.

You know, SCE is going out for wholesale market power, whereas PG&E is going out for somebody that actually builds new generation, so you're going to see pretty big differences in those two, which is, I think, very appropriate.

I'm going to sort of move really quickly through this, because I think this is relatively non-controversial and pretty standard. Most utilities, just like if you're a person going to borrow money to, to buy a house, want some kind of credit check, financial information. They want

10Ks if you're public, they want three years of audited financial statements, they want credit ratings.

And then I think where utilities differ is how, how detailed they want information about your project, whether they want like a full pro forma cash flow model. They want, you know, how you're going to get financing, what the ownership structure is, or if they don't ask for any of that stuff. So I sort of rated all these RFOs. I'm not going to go through this. Obviously, you can see this, read this in the report. But I think most, most utilities sort of are, I kind of rated them as average.

Development security. Some things, this is actually more typical real credit requirements. You know, development security is to make sure that the project is built, built on time, built to specifications. Development security is where your delay damages, your liquidated damages actually come from.

So in the, in the renewable arena, PG&E and Edison both use $20 a kilowatt, and they have, I think, for some time. I'm just looking at the 2006. The report goes into detail about previous,

previous RFOs. San Diego Gas and Electric just, in their 2006 RFOs, specified $10 a megawatt hour. And you can see the big difference here between the two projects if you notice that the, you know, even though the geothermal and the wind have the same rough annual generation, you can see obviously their development security is quite different. Nevada Power also does a per megawatt hour. I'm not sure why the nine cents, but that's what it is.

And LADWP has development security. It's just unclear from their model documents what that is. Xcel is quite a bit higher at $75 a kilowatt. And then Pacificorp has this enormous requirement for two years of revenue, which you can see is quite large. But they do have a collateral threshold here, so not all of that's going to be required to be posted. I'm sure the effect of that, though, is that really only incredibly creditworthy developers are going to bid. And I think we saw that with their, I think their 2001 RFO, they put out a renewable RFO for 1100 megawatts. So far, only one project has, has -- they've only signed one PPA from that. Perhaps that high development security might be one of the hurdles.

For non-renewables, PG&E is, is at 60 or $61 a kilowatt, depending on how you calculate it. SCE is zero, and once again, that's because Southern California Edison, that's a, that's a short-term RFO for marketing. Once the contract is signed, delivery starts the next day. There is no development period, so there's no development security.

Xcel, you can see is a little bit higher in there. And you can see all of the, for both PG&E and Xcel, they're a little bit, a little bit higher for the non-renewables. I spoke with APS. Their baseload, baseload RFO, you know, it's going to be really contract specific, so they don't have some set pro forma amount that they're using. It's going to really depend on the developer. There's going to be some amount but, you know, they don't have, they don't have a, a pre-set amount. It's going to be, you know, contract negotiation specific.

I'm going to talk a little bit about operating collateral. This is the collateral required post commercial operation date. And it's normally either calculated two ways. It's either a fixed amount, so based on some number of months of revenue, like three months of revenue or 12 months of revenue, can be based -- or, you know, as we've seen before, dollars per kilowatt, dollars per megawatt hour. Or you can do a mark-to-market calculation.

And mark-to-market is, is a way to capture the exposure of the project. And I mean, the example I used in the report is, you know, you sign a, you sign a contract for $70 power and if you think that the market, market power is going to go up to 75, your exposure is that $5 gap between the contract price and the, and the market price. And that's because if that contract fails to deliver you're going to have to go out on the wholesale market and buy power, and it's going to be more expensive.

One of the things that's about mark-to-market is it really requires access to forward price curves, it requires sort of a sophisticated financial statistical analysis. And a lot of smaller developers just don't have access to that information, tools, they don't have that expertise, they don't have -- you know, in a, I think Edison in some of their wholesale market stuff, the collateral amounts are re-calculated daily, so obviously there's somebody sitting at a desk looking at this stuff on a daily basis. A lot of smaller developers obviously aren't going to be doing that.

And the other thing about the recalculation is it makes it very difficult when you're coming up with your bid price to bid into the RFO, and you have to sort of build in cost for collateral if that collateral, those collateral amounts are going to be changing on an annual basis, it's very difficult to sort of know how much to put in for collateral.

There's also sort of what I call non-liquid collateral options, and these don't require a letter of credit or cash. These are things like subordinated mortgage or step-in rights. And these give a utility some protection and control of the project if, if, you know, like, let's say the parent company of the project company sort of starts starving the, the project company and doesn't do maintenance, and the, and the project's under-performing, that they can sort of step in and take over.

And these don't necessarily cost

anything in terms of money, nobody's writing a check. I mean, obviously, they, they cost some control. The, you know, developers and lenders don't necessarily like these.

So I apologize for the very busy, lots of numbers on the, on the slide. You know, PG -- these are, this is operating collateral for renewables. PG&E uses 12 months of revenue for 20 year terms, and that's what I'm showing there on the screen. Edison uses, very interestingly mark-to-market up until this year, where they've now done something interesting where they're asking people to bid for four different amounts of collateral, zero, three, six or 12. I'm actually showing 12 months. And then they actually include a subordinated mortgage.

SDG&E specified development operating collateral this year, it's $30 a megawatt hour. Xcel, you can see Xcel is quite a bit lower. Whereas their development security was much higher than everybody else's, now all they do is basically carry that development security over into operating collateral, and they add a, a subordinated mortgage.

LADWP is the same as San Diego Gas and

Electric. Nevada Power basically returns their development security after two years, and then requires no operating collateral. That may have something to do with the creditworthiness of that utility.

And then Pacificorp does 18 months of replacement power, which is a market, market power, which is the market price plus green tags, which allows it to calculate for renewables. And I used a $25 price for green tags here, and replacement power was just, I don't know, I think power ready spot came first.

For non, for non-renewables, there's actually in the, in your print-outs and in the report, I actually got PG&E's incorrectly. Their, their minimum $30, the $30 per kilowatt, and I believe $60 per kilowatt, is actually just for the first two years minimum, and then that goes away after the first years and then gets replaced with this mark-to-market methodology. And then, depending on technology, they're classified either as a two-year technology or a five-year technology, which is the, kind of the replacement time for the technology.

And then Edison is also, is using a

mark-to-market, and that's over the -- excuse me, over the five-year timeframe, that's fully collaterized. Xcel, just the same as in their renewables, is just basically carrying over development security and adding a subordinated mortgage. And APS is using some kind of mark-to-market methodology, and we're not, I mean, I can't exactly calculate it. All these calculations I used as sort of a possible market price of $75 a megawatt hour.

So just as an exercise, and because I'm an engineer, I decided to calculate what the cost of that operating collateral would be on a per megawatt hour basis.

UNDERSECRETARY DESMOND: Rick, I'm sorry. Could you just be sure to speak more clearly into the microphone for those listening in?

MR. O'CONNELL: Oh, I'm sorry.

UNDERSECRETARY DESMOND: Thank you.

MR. O'CONNELL: I'm sorry, Mr. Desmond.

So I tried to calculate the, the cost per megawatt hour. I'm assuming a two percent letter of credit fee here for all those collateral amounts we just saw, and you can see the sort of, you know, the, as a part of the price of power, what the operating collateral looks like. So it ranges from sort of, you know, just over a dollar in PG&E and SCE's, down to, you know, much smaller amounts in terms of Pacificorp and others.

And the same thing here in, in non-renewables. You can ignore that average. I mean, you can't really get an average out of three data points.

So I'm going to draw some limited conclusions. I really just sort of was trying to lay, lay the data out and just show, show people what, what people are using for collateral. I think an important point, though, is, is that the cost of collateral is more than just that carrying cost of the letter of credit. On the per megawatt hour basis, it appears to be, you know, low. Of course, I, I'm sure some people will think that $1.40 for collateral is too high, some people think it's fine.

In the renewable sphere, I think it really shows that using, when you use nameplate capacity to, to set security, you may be penalizing things like wind that have very low capacity factors.

And I think as, as we've seen, you know, mark-to-market looks maybe, could be inappropriate for renewable projects. They don't, renewable projects definitely aren't, aren't, there's not really a liquid market for renewable energy in California or in other places. It's obviously very difficult for renewable projects to calculate mark-to-market, and I think that, you know, Edison's recent move away from mark-to-market for renewables bears, bears that out.

So thanks very much. Appreciate your time.

UNDERSECRETARY DESMOND: Thank you, Rick.

I'm not sure we're going to have, go straight to questions, but I believe that the panel is going to be addressing this as they go through. So I'd like at this time to introduce Mr. Steve Zaminski. We're, we're on schedule here, and for the next two hours we will have Steve address the panel members. I'll allow Steve to introduce them, but before doing that let me just note that Steve is Senior Vice President of Starwood Energy Group Global, and has over 14 years of power industry experience, including roles as both a principal investment banker, management consultant, and independent power developer. And prior to joining Starwood, he was an investment banker with McManus and Miles, and prior to that with Deutsche Bank, Alex Brown's Global Energy and Utilities Group, and before that as a management consultant with Vantage Consulting.

He started his career in the power industry performing financial analysis in business development service, services for UltraSystems Development Corporation, an independent power developer, whose successor organization is now owned by LG&E. He holds a BS in Mechanical Engineering from the University of Maryland, and received his MBA, graduating with honors, from the Wharton School.

Mr. Zaminski.

PANEL 1 MODERATOR ZAMINSKI: Thank you, Joe. I am honored to be here today. Thank you for the opportunity, and I thank you and I applaud you for taking on what is a controversial topic here in California.

I would also like to thank the Commissioners and Executive Director Saltmarsh for attending and participating in what is a very important workshop here this morning.

Good morning. My name is Steve Zaminski. I'm a Senior Vice President at Starwood Energy Group, which is an affiliate of Starwood Capital Group. I, as Joe kindly pointed out, I started out my career working for a company based in Irvine, California called UltraSystems, which was a developer, and in the interest of full disclosure, we, Starwood Capital, Starwood Energy Group, have signed a 15 year PPA with Pacific Gas and Electric in April, and we also own five peaker plants in California, two in PG&E's territory and three in San Diego Gas and Electric's territory.

I'd like to introduce our distinguished panel, and we're very lucky to have this group here this morning, who are very well equipped to discuss the issues here. And if I, if I can, I'd like to try and attempt to do something very difficult, and that is to distill their long list of qualifications down to just a couple of lines, and if I get it wrong, I apologize in advance.

I sort of put this in order, bear with me. I think, let's see, does that match up, ABC? No. Well, not exactly. I'll go through this list in its order.

First of all, Terry Farrelly, from SDG&E. Ms. Farrelly oversees gas and electric supply procurement, including renewables procurement. She also served as a director of SDG&E's grid operations and manager of SDG&E;s fuel and resource supply. She began her career at SDG&E as an engineer in transmission planning, operations and generation engineering.

Tom French, with the California ISO. Mr. French is currently the manager of Grid Assets for the California ISO and is responsible for Cal-ISO's transmission and grid maintenance program, control area load and resource forecasting, providing general engineering support to the organization concerning transmission facilities, and managing the new facilities interconnection processes. Prior to joining the ISO in 2002, Tom spent 17 years with PG&E.

Joe Greco, with Caithness. Mr. Greco is responsible for asset management and expansion of Caithness Energy's West Coast geothermal and natural gas portfolio. Prior to joining Caithness in January of 2001, he served for six years at UAE Energy Operation's Corp, an independent Energy

Producer focused on fossil and bio-mass power generation technologies.

Tom King, with US Renewables. Mr. King is an independent consultant and partner of US Renewables Group. Over the past 15 years he has provided strategic and financial advice to clients in the power utility environmental and energy sectors. Previously, he was the head of energy and utilities within the Capital Markets Group of Dresdner Kleinwort Wasserstein, and spent over ten years with Chase Securities and was the head of Chase Global Project Debt Fund, LLC.

Tom Lumsden of FTI Consulting. Tom is a Senior Managing Director with 29 years of experience in workouts, reorganization and M and A's in service in numerous companies in the utility service and manufacturing sectors. Mr. Lumsden has extensive experience in process and financial assessment of clean-up, in the clean-up of hazardous waste soils and groundwater.

Kevin McSpadden is with Milbank, Tweed. Mr. McSpadden is an attorney with experience in M and A, capital markets project finance regulation, energy, and environmental law, and has been practicing in the utility/energy field for more than 16 years.

Pedro Pizarro is with Southern Cal Ed, a senior VP of power procurement. Mr. Pizarro's responsibilities include overseeing the procurement of conventional and renewable power contracts and the management and dispatch of SCE's overall power resource portfolio. Prior to SCE, Mr. Pizarro was a senior engagement manager with McKinsey and instituted performance improvement processes and addressed operational and organizational issues for clients in the energy, technology and engineering service and banking sectors.

John Seymour of FPL Energy is an executive director of FPL Energy. He is responsible for FPL Energy's wind energy development efforts in the western United States. Mr. Seymour has a BS from the University of Maryland -- go Turks -- and a JD from the Columbia University School of Law.

John Tormey, with Constellation Generation, Senior Counsel. Mr. Tormey's work consists of advising on all aspects of the company's project developments from project inception to financing. He previously spent six years as an associate at Chadbourne and Parke, where he represented both project developers and lenders with respect to the development of power plants, pipelines, LNG facilities, and other infrastructure projects.

And lastly, Fong Wan of PG&E, a VP of Electric Resources. Fong is responsible for the policies and administration of power supply contracts. Also, he is responsible for the longer-term electric resource procurement and development required to implement the utility's resource plan. This responsibility includes procurement strategies, auctions, negotiation of long-term power purchase agreements or resource development contracts, and the management of issued contracts.

Why are we here? Why does this matter? I think this slide says a lot. And I think the credit policies are a component of this issue. California ratepayers pay more than $2 billion a year more for power than, on average, the rest of the United States does. It costs more for California ratepayers to build a new power plant in California, and it's not for the reasons that you would otherwise think.

As an example, as an owner of five peaker projects in California and a builder of a new sixth project, we discovered it costs more than two times the national average to build here in California, and we can talk more about that.

California needs new power projects, not only renewables, but, as we like to think of them, renewable support from peakers and other power projects. This is an important issue and a, and a very important topic. Credit is, is a big component of this issue.

I'd like to briefly touch on our agenda today. Really, it's, I've distilled this down in two ways. Before lunch we're going to talk about what form and how much credit is enough. There's no right answer here. It's like asking how much insurance is enough. You're going to get different answers from different people depending on how conservative or liberal they may be. At the end of the day, though, it's ratepayers that are going to pay for this, so it's an important decision and we need to try to get consensus on this.

We're going to touch, Tom's going to touch a little bit on interconnection issues, which is another really important topic as it relates to developers and developer risk as they approach building new power projects for California.

And lastly, we'll try to wrap it up with some additional considerations which address some of these cost issues that are not covered by the topic of credit and make some suggestions as to future topics.

After lunch, which is Panel 2, we're really going to focus that on alternatives, and that's Gary's panel, and he'll introduce his panel members at that time.

This is a sort of detailed granular list of the topical areas that we're going to try and capture, and they're not necessarily in this order. But a couple of housekeeping items. One, I, I challenge the panelists to try and adopt something that's very hard. Avoid self-interest and try to analyze this issue in the context of what's best for the ratepayers, not what's best for yourselves. And I, I, too, face that challenge when I deal with this topic.

The second thing is that this panel is really trying to analyze this issue in the context of the public policy. Well, it's not a public policy, but just let's say the corporate policy. And secondarily, its implications as it relates to the ratepayer effects. And we're not really trying to address alternatives this morning, that's for this afternoon, so if we can try and avoid that topic and leave something for this afternoon, that would be very helpful.

So how did we get here? What is the rationale behind current credit requirements and what is the historical perspective on critical -- on PPA credit requirements. We're very lucky to have the California's three IOUs here to talk individually about their policies on this issue, how they came to the conclusions they did, and how they implement them.

And we will try to address these three presentations. First Fong, second Pedro, last Terry, and then open it up for Q and A. And I'd ask if you would please try and hold your comments or questions until that point, that'd be very helpful.

And with that, let me have Fong come up and we'll see if we can get his presentation to appear on the screen.

MR. WAN: Is this on now? Can I just stay down here, is that okay with you guys? Okay, great. Thank you.

Pedro, Terry and I spent a few minutes yesterday to coordinate among our three presentations, and we are going to try to avoid having duplicate, covering duplicate topics.

First, I wanted to thank Rick for giving an excellent presentation earlier. The information was pretty accurate.

PG&E's credit policy evolved out of and is consistent with industry practice for the energy markets. These industry standards come from mass agreements developed by Edison Electric Institute, North American Energy Standards Board, and the International Spot Dealers Association. The primary elements of these standards include collateral thresholds that we talked about earlier, which is linked to your debt ratings, the cost of the mark to market posting, and the contractual termination provisions.

Can I trouble you to -- yeah. Thank you very much.

What I really want to touch on today is that if you look at all of our presentations it would look like what we're after is money. I want to change that perception. What we're after is performance. And what we're trying to do here is to make sure we have enough power to avoid another energy shortage, energy crisis. What we're also trying to do here is to make sure we can meet the renewable goals that the State of California wants.

Credit risk of an electric contract is the possible loss associated with a supplier default under the contract. And it's normally specified a particular probability level. Some companies use as low as 80 percent, some companies use as high as 99 percent. And it's also calculated over a particular time horizon. In general, the longer the contract, the more likely to default.

Perfect. Thank you.

The two major type of risk, credit risk that PG&E, for PG&E and our customers. The first one is payment risk. This is really where PG&E sells power to others. You have to remember that utilities are also big sellers of power during certain times of the year, so we have to structure all of our agreements in which the agreements are symmetrical in credit terms and provisions.

The second one is performance risk. This is a risk that a supplier fails to perform its obligations under the contract. It could be for failure to construct as well as failure to deliver the power.

In terms of performance risk, what we're really worried about is when market prices go lower, because that's when we face the possibility of a seller deciding to sell the power to somebody else, and it does happen. And we have seen it during the energy crisis, we have seen it, we are seeing it happen possibly today. And I'll go into a little bit of that.

When that does happen, we are forced to replace the power at a higher price than prevailing market price. Again, our credit policy is to make sure they perform because, after all, money doesn't do us any good if we're short of power.

In terms of mitigating performance risk. We have two components, one is collateral, we talked about earlier. The other one is contract terms and conditions. And I was just thinking about this last night. All of us, when we first got out of school, we all rented apartments, and we all had rental agreements. The rental agreement spelled out clearly what our obligations are, and that's the contract terms and conditions. We were also forced to post some rental deposits. That is to make sure we actually fulfilled our obligations.

As long as things went through smoothly, which was in my case I always got, I always got my rental deposits back, so we are not trying to keep anybody's money. What we're trying to do is to make sure that people perform according to the contracts.

In terms of collateral, Rick mentioned earlier we have several stages. I look at them as three stages; when they submit an offer, during the construction period, and during operations. The risks are quite different in each of the three stages.

Steve.

In terms of the offer deposit. What we're trying to do here is to avoid and mitigate the risk of unreliable offers. We're looking for legitimate bids because it takes a lot of time and effort to analyze the offers. I will tell you in our 2003 RPS RFO, one seller provided 28 offers and we had a hard time even contacting the person, and that is when we started to move toward a bid deposit. And Rick captured it correctly. In the RPS for 2005 and 2006 solicitation, our bid deposit or offer deposit is actually a time when we short list the offers, not at the beginning of the, the whole solicitation.

In terms of during the construction period, this is something that we monitor very closely, because what we're trying to do is to avoid any delay or failure to complete. We want all of our projects, whether it's conventional projects or RPS projects, to be there and deliver actual energy.

In terms during operations. This is where we are. We have faced, and we continue to face challenges. I can tell you that Pedro and I, along with the State of California through DWR, we are participating in Calpine's bankruptcy in which there is at least 1,000 megawatts of non -- that Calpine is trying to not perform on the DWR contract side, and I have a hundred, and I think you have 200, on the renewable side. So these risks are very real, and these risks do run into a lot of complications when they're going into bankruptcy.

And why would people trying to reject contracts is because they have an alternative market that would pay them more. So when we hold collateral, we ask for performance, we're trying to avoid non-delivery.

In terms of posting collateral, Rick talked a little earlier that we have two approaches, a mark-to-market posting, which is fluctuating according to market prices, and the second one is a fixed concept, a revenue-based posting. It could be six, 12 months or so, in terms of posting.

My last page before I turn it over to Pedro has to do with termination. Termination payments happens when either the buyer or the seller defaults, so it happens both ways. The contracts are always clearly laid out in terms of the conditions when either the buyer or the seller defaults. The party that suffers economically from the default is entitled to a termination payment. This termination can take place pre- or post-commercial operations, and it's always easier to collect on this payment if one is holding a collateral.

And I can speak that PG&E has had a lot of experience in trying to collect. During our bankruptcy, we collected over half a billion dollars in termination payments from Duke, Enron, and Mirant. So this is a big issue and there is a lot of money at stake.

MR. PIZARRO: I wanted to come up here to better control the advance and timing of the slides, if that's okay with you guys. That's sort of how we had envisioned it. Or would you prefer to sit there?

(Inaudible comments.)

MR. PIZARRO: Well, I wanted to add my thanks also to the organizers for bringing us together here. I'll try not to repeat what Fong and Rick and others have already said well about some of the details, but I'll try and provide some context.

I do understand, however, that Fong, during your discussion, Gary Ackerman and Steven Kelly already hired an independent evaluator to confirm that you never had to leave some of your collateral deposits behind on your rentals, so we'll, we'll have results by lunch, I hope.

This is an important topic, and I thought I'd place it in, in the context of what the utilities are doing and what our objectives are. Fong covered this briefly, but we're out here to serve load, and we're doing that through a least cost-best fit procurement, whether they're non-renewables or renewables.

We do that by contracting with many of the folks who are in this room, and at the end of the day we're trying to manage risks. And I think, as you've seen from some of the movement that we've made in the structuring that we're doing for deposits and for collateral as we move on, we are trying to get a sense of what's the right balance for customers between levels of performance protection and the implicit cost of that.

And I thought Rick did a nice job of teeing up that yes, there is a cost, it's a small cost relative to the overall price of, of the energy and the capacity being delivered. I think there's another dimension to that, which is you do get what you pay for. And a lot of this is about deciding what level of insurance, what level of performance protection is appropriate for customers to look for in contracts and, and how much are they paying for that.

Fong covered this area very well, but again, as we look at performance protection, a point I'd like to emphasize is that credit is just one element. And this whole notion that there are other issues that are covered in contractual terms and conditions is really important because, as we think about a contract, it's not just a price and a credit posting. It's a price and it's 60, 70, 100 different terms and conditions which include credit and collateral, but which also include performance obligations, maintenance obligations, heat rate guarantees, other elements that are all essential to defining performance assurance.

On the next chart I also wanted to point out that beyond credit, and as you look at also beyond some of the contractual terms and conditions, there are other issues that are governing how we contract and ultimately how resources, either existing resources get contracted for or, importantly, how new resources can get developed in the future.

We have the whole generator interconnection process, and I think that we may get into that in some of the other discussions. Permitting and siting issues, there's transmission availability, there's the need for long-term contracts and, and how that works in a retail environment, which the PUC is looking at right now, and then how the state progresses with its balance between renewable and conventional resources.

So all of these come together to create the procurement environment that is complex, that will hopefully get the job done, but that has a lot more elements to it than just credit. So I just wanted that as a reminder that particularly when we hear sometimes in the community that it's credit that's the issue, well, no, credit is one consideration. There are many others.

I wanted to spend a couple of minutes on this slide, because I do think it's important to provide some historical context. And again, as you look back to 20, 30 years ago, when we really saw the creation of the independent power generator market, a lot of that was driven by PURPA. In California it manifested itself with contracts like the standard offer fours. The environment was different there.

Utilities were still vertically integrated. The contracts that we purchased from third parties represented a fairly low percentage of the overall utility portfolio. And those contracts, because they had some strong policy incentives ended up being fairly high price relative to market, so from a generator perspective there was little incentive to break that contract. And put all that together, and were in a very minimal credit requirement environment.

As we headed on into deregulation, 1890 in the state, but beyond California the emergence of power marketers and other entities stepping in to create the electric markets, we saw a couple of things happen. One was there was a level of greater sophistication needed that, frankly, the third party marketers and others started bringing into the environment, looking for what kinds of rules, what kinds of commercial terms and conditions would guide wholesale procurement and would guide those -- bilateral negotiations between counterparties.

And then we saw the, the downside of the markets as we saw the first major default with the federal energy sales experience, saw the California energy crisis, we saw bankruptcies across the country. Fong I think covered it well, that as we were headed into that period, the utilities frankly were playing catch-up with some of the other parties out there, like the power marketers, but we had caught up enough to have the initial set of lines of credit established -- sorry, letters of credit established, and other performance protections. So we did see some performance mitigation as we entered into defaults, saw defaults from some of our counterparties in, during the energy crisis.

So those requirements were stepping up. And I will point out, this chart is updated relative to the copy that you have on paper. Just somehow the, the update didn't make it. But basically, showing you there was a step-up during this period.

Remember, though, that the utilities left the procurement function through deregulation, and we then had to step back into it. We were at a point then wherein our balance sheets were deeply imperiled. PG&E was in bankruptcy, Edison narrowly avoided it, and the rating agencies, who were an important set of participants here, were looking very hard at us. And they still do. I spend a lot of my time during the course of the year making sure that the rating agencies understand how our balance sheet stands relative to the contracts that we have outstanding, and what the credit protections are that are built into that.

So as we headed back into procurement in the '03 timeframe, we saw a step-up in our credit policies to ensure that we could weather the aftermath of the crisis, sign contracts that we could count on, and also protect our balance sheets.

Where are we today? We're learning. And we're still learning. We've been able to refine the requirements. Again, Rick pointed out that we've tried to bring the balance back in and, you know, let's face it, there's a pendulum here. For SCE, that has meant, for example, recognizing, through a lot of input from many of your, that working with mark-to-market on the renewable side is very challenging and complex, simplifying that by providing more flexible collateral options, eliminating, in the case of the renewables, our bid deposits. And I think you'll see other changes as we all continue to learn together.

In spite of, of the complexity, we have all been successful in singing contracts. And again, many of you are counterparties with many of us. And, you know, we've executed renewable contracts for new generation at SCE. We've also done our all sources for existing. We're hoping to go to the market for new gen on the conventional side shortly here, pending a PUC decision. We may have a capacity market in the future. We're more likely to have a capacity product in the interim. All of these are going to continue to drive an evolution in the performance assurance and, and specifically credit requirement landscape.

And so as we look at next steps, we are certainly open to alternatives. And my staff put this little picture here, that may be a depiction of me. I'm a little concerned about that, but we really are here to listen. And hopefully, we'll be listening a lot during this workshop and on into the future.

MS. FARRELLY: Hi. I'm Terry Farrelly, I'm with San Diego Gas and Electric. And I appreciate the opportunity to be here with you today. It will be a little bit difficult not to do too much of a -- okay, too much of a repeat. But I wanted to just go over a little bit about our general credit policies that we do use mark-to-market. And we take a look at that, and we have -- it is, it is quite a complex calculation to do that. And we go through the mark-to-market. This is for the non-renewables right now. And then our credit department takes a look at that magnitude of the mark-to-market, and works with the bidder to determine if there's unsecured credit that can be utilized, or if we look at secured credit, or a combination of both.

What we found as we were going through some of the renewable RFOs that this process didn't work very well for the renewables, and so, so we decided to make some changes. So what we did with our renewable contract credit is that we came up with some key components.

We did have a project development fee. We put that together, and we included it in our policy. We saw that -- we've seen a need to waive that as we go through the RFOS, but we continued to evaluate that because we do think that there's probably a need for that, at least on the short list. After hearing Fong talk today about how many bids you got, I think we're learning, learning, learning. And so I appreciate all the information so that we can go ahead, and we are re-evaluating some of these policies. And so we may look at some sort of a project development fee in the future.

Also, the project development security. What -- we looked there at a minimum of, say, two years, what's the annual production over two years. That would give us a little bit of time to adjust if, if a project wasn't going to go forward. And then two years times a development target. In the most recent RFO we targeted about $5 a megawatt hour. And that would be due after the conditions precedent in the contract were met, and then it would be refundable once the commercial operation date was achieved.

And we also have a default security. That is after commercial operation date. It's the same thing, it's for production over a two-year period, and we have targeted $15 in our most recent RFO. To the extent that we can do some things, such as negotiate step-in rights, that also helps us in working through the security requirements.

Most of the time our credit department will get involved in this as we go through the negotiations. This is, this is done as part of the negotiations. It isn't a date that a party has to get through first of all. What we want to do is we want to see that these projects are successful. We want to be able to put contracts together for renewables. We want to make sure that they can do the financing, and we want to make sure that they're able to, to operate.

So we have tried in the past to work to make sure that we are middle of the road in terms of what our credit policy might be. I think, based upon the presentation this morning with Black and Veatch, and from the -- report that, that I have read, it's just the utilities were not quite consistent on some of the securities, but I think we're a little bit higher in some areas than PG&E and Edison, and then we're lower in other areas. But what we're trying to do is come up with something that's reasonable, that protects the customer, so that if there is a, a default, or if the project doesn't come online, that, that there would be something there for the, the ratepayers to fall back on while we go ahead through, say, a two-year period to be able to replace the resource.

So, like I said, we want to work with the bidders. We are reviewing our policy right now. We are in the learning mode, and I would be very interested in hearing the comments that we'll get today.

PANEL 1 MODERATOR ZAMINSKI: Thank you, Fong, Pedro, and Terry.

So this is the spirited debate component of the panel. I would encourage as many to participate as possible. And I'd like to open to the panel to comment on some of the presentations.

UNDERSECRETARY DESMOND: Steve, before that, I believe some of the panel members up here also had some questions. I want to provide them with an opportunity.

Commissioner Bohn.

CPUC COMMISSIONER BOHN: Yeah. Thank you very much. It's been, it's been very interesting. I, when I first saw the title of this I was trying to figure out what on earth it's got to do with credit, at least in the context with which I'm familiar. Let me, let me back up a minute and ask, and maybe the panel can, can comment on this. If a utility is building a power plant in-house, it has most of the same risks that we're talking about. Risks. It could come in late, it could come in defective in therms of capacity is concerned. It could go down in operation and therefore the utility would have to go to market to, to pick up that energy. And as I look at the presentations here, it seems to me we're talking much more about performance risk than we are about credit. I think Pedro had it right, credit is interesting. But the reason you look at credit is to give you some indication of the likelihood of performance. That's the whole part of that analysis that makes sense.

I'd be interested in hearing a, a comment about if a power plant were to be developed in-house, how those same risks are dealt with, because implicit somehow in the corporate process is a risk evaluation. Either it's not as risky if we're doing it in-house, or if it goes down we have ways to ensure against lacking the power. I'm, I'm puzzled about why some of these risks are attributed uniquely to independent power producers, as opposed to implicitly in terms of building the darn things yourself.

PANEL 1 MODERATOR ZAMINSKI: Pedro.

MR. PIZARRO: Let me take an initial stab at it, and I think that is a good question, Commissioner.

From the perspective -- let me answer it from two different perspectives, and I'll start with the customer perspective, which I think is probably the most important one here.

From a customer perspective, yes, I think we're looking at performance risk regardless of who the owner of the project is. The presentations here focused, I think by design, on how you manage the risk in that supplier/buyer relationship. From a customer perspective, if we're talking about a utility owned project, there is a whole reasonableness risk exposure to the utility which is also a protective, a mitigator for the customer in that utility owned projects would be done under Commission oversight, with Commission approval of cost recovery.

And I think we're seeing this right now, live examples, in what PG&E is doing. We saw it recently with the Mountain View plant. There's a, ultimately, there's a regulatory compact there that says here are the parameters that the PUC is approving for the utility project, and beyond that, if there is not the performance versus those parameters, then the PUC ultimately has tools to ensure protection, if you will, by adjusting or guiding what portion of those costs shareholders ultimately get to recover from customers.

Now, that doesn't address fully the risk of how you get the power, and at the end of the day what we're concerned about is making sure we have the electrons flowing when we need them and where we need them, whether it's through contract or whether it's through utility owned plant. But what it does say is that in the case of third party contracts, the customer protection comes from the credit and other performance parameters that are negotiated with the counterparty. In the case of utility owned plant, to some extent the financial mitigation for that comes from the cost recovery approval process and oversight that the PUC provides.

So, you know, that, that's -- now, from a utility perspective, which was the second context, second angle to answer this. It is a little different in that the cost of the project for a utility owned project obviously gets carried on the utility balance sheet. The cost of the third party projects is getting carried obviously on the IPP balance sheet, but there is that equivalent that, as you know, the rating agencies are assessing. And so I think part of what the rating agencies have been doing is in their own way, and I think we, probably all of us have different levels of disagreement with what they're doing, but they're trying to mitigate some sort of debt impact on the utility balance sheet to bring third party obligations on, quote/unquote, more equal footing with debt on the utility balance sheet. And that's a whole other can of worms that probably merits its own discussion.

But that's the second angle of viewing of what's the impact on the, on the utility balance sheet as opposed to from the customer perspective. And, and debt equivalence is creating a more direct comparison between the two.

I don't know if that gets to your question, Commissioner.

CPUC COMMISSIONER BOHN: Yeah, that's, that's helpful. Given that, however, how would you ever have an independent power producer be able to submit a competitive bid when measured against internal power production?

MR. WAN: Can I take a shot at answering that question? I think these are really good questions.

I would actually break down the performance into two separate categories. The first category has to do with more whether somebody is really going to perform and sell you the power, versus selling it to somebody else. The second category has to do with the construction, the operational issues you mentioned earlier, which would be similar between an IPP and a utility generation.

Let me address the first one. What we witnessed during the energy crisis is that a lot of parties with PPAs to the utilities all terminated their contracts. And --

MR. ZAMINSKI: Fong, you've got to speak into the microphone so we can hear you too.

MR. WAN: Sorry, Steve. A lot of parties chose to terminate their contracts with the utilities and the most reliable generation for the utilities were actually our own. And these parties took the power and sold it to others at a higher price, further exposing our customers to the very high spot prices. And so from that perspective, utility generation cannot leave our customers. So that's the first part.

The second part is really a business model issue, which Pedro was trying to touch on. The IPPs have market-based ratemaking, or whatever, they, they're not under cost of service, and they will submit their best prices and take in consideration all the possibility or delay in construction, and bad operational outcomes during operations, and try to price all that risk into their prices.

Utilities go through cost of service ratemaking, where our upside is capped per the Commission, and the rate of return, and we go through a process that Pedro laid out earlier, which is the Commission has jurisdiction and oversight in whether we're late, whether we overspend, so they're two different business models and the risks are all addressed differently, in my opinion.

So, so it is hard to evaluate the two business models in a head-on competition. I think that was your follow-up question. And that would be consistent with the testimony that the utilities submitted in their long-term plan. They're not very comparable across.

CPUC COMMISSIONER BOHN: One last question, Mr. Chairman, if I can, and then I'll back off of this.

So the risks of construction, the development -- qualifying the bid, fair enough. Risk of construction delays, fair enough. Any kind of construction process is, is basically the same. So the concern is, is the reliability of the sale of power, which -- I mean, leave bankruptcy aside for a minute, because the bankruptcy judge can do almost anything the bankruptcy judge wants to do, and it's pretty hard, other than through ownership or priority liens or whatever it is, to deal with that.

But, but leaving that one issue aside, is the principal risk then the concern that the sale of power, that the people will simply stop selling it to you? Is, is that the issue, or is that the principal issue?

MR. PIZARRO: That's one of the issues. I could give you another example. The, the bid deposit that we showed earlier is $3 per kilowatt. And if you translate that like Rick did for a hundred megawatt wind project, that's only $300,000. And the seller shall remain unnamed. They may have a project with us, or they may have a project with some other utility in Texas or Europe for a wind project, and $300,000 is a very low bid deposit to forfeit if they can get a better contract elsewhere.

And that is happening right now across the country and worldwide. It's not a lot of money, because other, other markets sometimes give them a better bang for their free option they just, they just got.

CPUC COMMISSIONER BOHN: That's right. Thank you.

PANEL 1 MODERATOR ZAMINSKI: Just as a, as a follow-up, and I throw this out to our IOU representatives, is it correct to say that one of the distinctions between how the ratepayer may be impacted by a project that is developed by a utility versus one that is developed independently, is that the utility may or may not get reimbursed through the prudency review of their costs, whereas an IPP is, in fact, absolutely held responsible for what happens. Is, is that a fair statement, or is that not fair?

MR. PIZARRO: I, I think, I think that's, that's one of the descriptions, or one of the parts of, of the differences here. With an IPP you do have a legal contract that specifies delivery at a certain price and under terms and conditions. And when you go back to the Commissioner's question around from the customer perspective how does that translate, what does that translate into in the event of a non-performance event, then you have contractual remedies in the third party IPP contract, versus Commission oversight and ultimately cost recovery decisions on the utility side.

But I want to underscore something that Fong made, Fong said in this discussion. We view these as very different, and frankly, very complementary animals in our portfolio. And we think that there is a lot of benefit to our customers in having both the option of third party contracts and also the option of the utility owned generation under the right conditions.

Today, and you've seen our disclosure here, something like two-thirds of the electrons that we at Edison provide to our bundled customers come from third party providers, and we don't expect that to change appreciably. It may even probably increase over, over the next few years, because it takes a lot of capital to be developing new generation and we're using a lot of our capital right now for wires development. We just don't have the financial wherewithal to tilt that balance down to where we would be providing 70 percent from utility owned.

So I don't think that's the issue, but the issue is how do you make that comparison between utility owned and third party contracts in a fair way. The Commissioner brought up the concept of, you know, the head-on competition. I know PG&E has just been through their exercise and, and have filed testimony. But at the end of the day, having a fixed term contract, ten-year contract, twenty-year contract, versus -- at a, with a built-in profit and a, a view by the third party of the risk and rewards, versus a contract that's a cost of service animal for the life of the -- for the life of the asset, those are very different value propositions to customers.

And I don't, frankly, I'm not smart

enough to reduce that into a formulaic exercise. There's, at the end of the day judgment that is involved here on the part of the Commission and what that balance needs to be between the two types of elements, a fixed price and a cost of service element in customer portfolios.

UNDERSECRETARY DESMOND: Any other panel care to comment?

MR. TORMEY: There are a couple of things, I guess, that --

UNDERSECRETARY DESMOND: Please identify yourself.

MR. TORMEY: I'm sorry. My name is John Tormey. I'm with Constellation Energy.

To the, the Commissioner's question, I guess, and just a comparison, I understand what Pedro and Fong are talking about, sort of pre-construction, they, they potentially run the risk of not getting their cost rolled into rate base if something stops ahead of time. That's not, in my view, unlike sort of the bid deposits and completion deposit.

From an operations perspective, I guess I would, I would point out that the credit, the collateral requirements that we have proposed to me do make it somewhat difficult to compare an IPP to a utility, simply from the fact that if we don't perform, if we don't perform we won't recover our costs, not even the fixed costs of capital, or a return or anything else.

If the cost of the plant had already been rolled into rate base, by and large they, they are assured of recovery. And if their plant doesn't perform, and they may take issue with that, but if their plant doesn't perform they also have a, a -- in either case, they will likely be able to go out and procure power elsewhere and recover those costs, as well.

So in terms of the, the risk that, that we have taken as an IPP, I guess I would point out that we are taking an operating risk on top of being asked to put up what at times are pretty significant collateral requirements that increase the cost for projects in our view is, is a much greater risk on us, cost on us, than an IPP plant.

Also, Pedro made the point that he's viewing something from a utility perspective, which was the, the debt equivalency issue. I understand that, that equivalency issue, but I didn't quite, I guess, understand how it, it plays into this necessarily.

And then also, I guess also in terms of the, the reference to the market based rates that we're entitled to recover. I would point out that by and large, I think because we have to compete with each other, the rates of returns that, that most of the clients I had when I was at Chadbourne, and I will point out that for Constellation, as well, by and large on an un-levered basis, lower than the rate of return that the utilities get for a project that is far less riskier in terms of recovering the costs that I would say that the IPPs are, are taking, we're, we're entitled to lever up the project at rates that are frequently much higher than the utilities, and so our, our levered returns look much better.

But from a ratepayer perspective, given that our unlevered returns, the hurdle rates that most of us have are lower than the, the guaranteed rates of return that the utilities get. Our cost is frequently better, as well, in terms of what we ask for in profit.

So I, I'm not sure that the market based rate issue is necessarily something that is, that plays to IPPs having a, a better shake, so to speak.

PANEL 1 MODERATOR ZAMINSKI: That was fairly non-controversial. I saw some heads shaking over here.

MR. WAN: I'll give it a shot. First of all, I want to say it's risk and reward, not only risk. So we've got to look at both sides of the equation, and utilities do face a use and usefulness test. So after a plant goes into a rate base if it's no longer in operation we have a tough time getting our money, the principal back. We definitely don't have a chance to get our return. So, so this also applies to us.

And I want to mention something that's somewhat public, that is in our long-term RFO we received over 50 offers, so there are lots of people interested in this business. And I will also say our facilitators firm is one firm that came up after the winning bidder was essentially chosen, and that's not the only one. So there's lots of equities participating and buying into projects that's been selected, so obviously the return must be good enough for Steve and his firm, and other firms out there.

And what Pedro mentioned earlier about debt equivalency is what all the rating agencies do, and S&P is more specific, specifying that long-term power purchase contracts have debt-like equivalencies on our balance sheet, and we debated this in front of the PUC as to whether it's 30 percent, it's 20 percent, or ten percent. You can talk to Moody's, S&P, and anybody. It is real. So it is a cost to the utilities.

MR. TORMEY: I don't want to get necessarily back and forth here. The debt equivalency issue, I was trying to respond to the Commissioner's question as to whether or not the IPPs can compete, compete fairly with a project from a utility. The, the debt equivalency issue might be something that's well worth bringing up, and whether or not you guys are entitled to return if something that perhaps should be getting discussed. I don't disagree with that.

PANEL 1 MODERATOR ZAMINSKI: Question?

MR. LUMSDEN: Tom Lumsden, with FTI Consulting. I just wanted to echo the comments that in terms of looking at the, looking at the operational performance characteristics once a plant is running, there are a number of things that can cause a plant not to operate, not because of the operator error or developer error. It's just, you know, the wind isn't there, the steam reservoir isn't there, various other natural events occur. And frequently, in my experience, I see the IOUs, their plants are allowed to essentially recover those costs of the interruption through the normal rate base process and through operating costs, whereas a independent operator is essentially bearing that full risk. Some, some things they can insure through various credit means, but by and large it is a, an equity risk that the investors are taking that project.

The other thing that, to consider is that while the S&P and Moody's and the other rating agencies are essentially applying the debt equivalency, I would be curious to inquire of the IOUs as to whether they, in their discussions with the rating agencies, have they been able to put forth the argument that the credit requirements that they're requiring independent generators to post for their PPAs, whether those essentially are allowing them to lower those debt equivalency requirements. Are, are you getting benefit for the requirements you're charging the IPPs, are you getting benefit in the ratings process.

PANEL 1 MODERATOR ZAMINSKI: Thanks, Tom. Pedro, do you want to respond?

MR. PIZARRO: Yeah, I can respond to that.

As Fong said, S&P tends to be a little bit more methodological about it, Moody's a little bit more black box. They're both still black box to some extent. I think that one of the biggest drivers for debt equivalence right now is just their view of the overall environment. And as much as we tell them that the environment in California really has improved significantly -- and, by the way, from their perspective it's not just about the market, but the regulatory environment, how, how are the folks behind us here doing in terms of establishing a good stable environment that's predictable. You know, we, we feel that there's been just significant progress since the energy crisis. Rating agencies are still a little slow to, to be proven that.

So to your specific question, to what extent did, you know, the credit provisions help with debt equivalency, I, I firmly -- I would -- I don't think a whole lot. I think they're looking more at what is the risk that this debt-like instrument, which is an obligation to have a contract, what's the risk that we won't be able to recover the cost for that debt on our balance sheet. And so it really becomes one, an issue more of the pass-through ability, the regulatory cost recovery mechanism.

The, the other comment I'd make on the point you were making in this just back and forth, which is an interesting one, is I want to be clear. At least from our perspective, I'm not talking about one or the other, utility owned or PPAs being better. That's the whole point. They're different. They're different. They involve different sets of risk and reward. I do agree with Fong just in the comments so far, there's been a focus on the ability for utility shareholders to mitigate some of their, the risk to cost recovery, but there's also a lot of risk exposure that they still have.

And oh, by the way, in the flip side, there's reward that's flowing back to customers through the cost of service model, and one example is with Mountain View, because of the bonus tax depreciation rules that the federal government had set up after 9/11, we were able to accelerate that project, bring it online, have it be essentially complete by the end of last year. And that created a large bonus windfall of -- I forget the exact number, over $50 million that went straight to ratepayers.

So again, it's not better or worse. They are different. And to me, it's like when I'm putting, setting up my financial portfolio, you know, you like some fixed income, you like some, some equities. It's a similar sort of portfolio management decision that, you know, utilities make and that ultimately the Commission has to provide oversight for.

So, I, I just get concerned when we get into the back and forth, trying to prove one model or the other. That's not, that misses the point. These are different risk instruments in managing a portfolio.

PANEL 1 MODERATOR ZAMINSKI: Thank you, Pedro. In the interest of trying to get through what we have today, I was going to run through a couple of additional slides and open it back up to the panel for Q and A.

A couple of things, just make some

observations about renewables. And really, Joe's part of -- correct me if I'm wrong, Joe, but a large component of your concern about this issue is really with respect to meeting the RPS requirement here in California, and this has implications there and, you know, some observations about renewables that I think are important for context.

As I think it's been said, renewables tend to be very small. There's a lot of them that need to be built if we're going to make the 2010 requirement. We all know that. And I think the credit requirements for small entrepreneurial developers are, are really quite difficult. It's, it's a little easier for some of our panelists who come from big balance sheet companies to deal with these credit requirements, and they're doing a great job of building projects here in California and other places. But if you go back historically to what California had opened the door up to a lot of small entrepreneurial developers to be able to enable them to build, I'm not sure the case is true.

And I would suggest that I believe, and I say this selflessly, because I'm one of those guys who can provide the credit, as I have, this doesn't help me at all. But it's, it's clear that it's hurting the small developer. It's, it's making it very difficult for them. And I think if you consider who did sign contracts in PG&E's recent RFO that we were a part of, there were no small developers. It's two private equity firms. and I guess the Commission needs to ask themselves is that the direction that we want to go.

I know my answer. Sure, let's keep going. But selflessly, I think there's a larger question here, and we really need to take a hard look at that.

There's some non-quantitative aspects to credit which I think far outweigh the quantitative aspects of credit. As, as we look at developing a project to support renewables, a small peaker project, we're looking at -- and, and there's some confidential information here, but in round numbers, roughly ten percent of the total capital cost is going to be out the door before we get to construction financing. And for non-development people in the audience, construction financing is, is nirvana and it's, it's where you want to be. Your risk kind of goes down a lot because you're, a lot of what's going to happen from that point forward is, is going to be funded by the bank. And in order for that to happen, you've figured out most of the problems that exist in development.

And so ten percent of the capital cost out of pocket is a big number relative to the overall project. But what really happens through credit is you're doubling that, almost. You, you're going from ten to almost 20 percent of the capital cost to build a project. And I think that's probably, you know, something to really think about. If I think about one message that I discovered in my analysis of this issue, it's that. And how many companies are willing to do that? How many companies are able to do that?

And so this is a very significant issue. I think it has a profound effect on competition, and, you know, there may have been 60 people who submitted proposals, but if you look at who came out the other side it's a very uniform, homogeneous group of people. And that's, that's an interesting question for the Commission and, and folks to consider because I think that tells us something.

And, and the point came up about controllable risks. And I don't want to, as Pedro is appropriately pointing out, I don't think it's appropriate to have IPP versus utility, but rather, should, in the independents' case, they be held for things which are outside of their control. And, you know, there are a lot of uncontrollable items that are faced in the, in the development process that if you're going to have these credit requirements, I think they really need to recognize that some of this stuff is really outside of the developer's control and they should not be held accountable for those items.

When we did a quantification of the credit costs, and I apologize for these footnotes. Hopefully they show up a lot better in the printed copies that you have. But the way that we came up with it is on a renewable project in, largely in most areas, California is no exception, that means wind, it adds about six percent to the capital cost of a wind project. That is significant. Very significant. And I'd be happy to share after the fact of the calculation methodology that we used to make this back of the envelope, maybe a little more sophisticated than that, attempt to quantify these costs.

Here's something we know a lot more about. Peaker projects. We own five, we're building a sixth. Here, the adder is a little higher because the capital cost on a unit basis, dollar per kW basis, is a lot lower than a renewable project. It's nine percent. This is that doubling down effect that I was referring to. Ten percent our of pocket real cost. And then there's nine percent that could be out of pocket if something happens.

So you could risk 20 percent of the cost of the project, and in some cases, for things that are completely outside of your control. And that has a profound effect on the state's ability to get small guys to step up to that risk. That's, that's a big risk.

If you measure that on a what's it each year, we had the luxury of having this sophisticated Xcel model which maps out our economics, and for the record, they are actually below on an after tax basis what the IOUs are getting on a regulated basis, and it's about eight percent. If we -- and let me just explain, because I think hopefully it's not so complicated that it is easy enough to explain.

What we did is we simply took our model, which has all the credit requirements in it. We removed them, and we lowered our capacity payment to hold the economics the same. Eight percent lower capacity payments on average. That's the real cost here.

And let me go back, if I could, a couple of slides, because I want to, with that, hopefully liven up the discussion a little bit.

MR. WAN: Well, Steve, before you -- can you help us reconcile your numbers versus Rick's? They're very different.

PANEL 1 MODERATOR ZAMINSKI: They are. I, I would, I would characterize -- I'd like to think that our numbers represent a very comprehensive review for someone who's actually building in California. Rick took on an incredibly difficult task in trying to digest and compare credit policies across the western United States and try to approximate some of the effect of that on a capital cost basis and dollar per Megawatt hour basis.

I would suggest that, that what we did is we have six power plants, five of which are operating, one we're developing, and we took a view of that recognizing that not only does the carrying cost of the credit affect cash flow and out of pocket cash flow, but it also affects debt capacity. And so we tried to be agnostic to credit or no credit in, in our requirements, but I, I think that discussion, I'd -- welcome to have that discussion, but I'm not sure we're going to get through. I, I can walk through the math and I've got a spreadsheet I'm happy to share with you.

MR. WAN: It's actually pretty simple. In Rick's presentation he has in a footnote that the credit fee is two percent of the collateral amount. Are you saying it's 100 percent?

(Parties speaking simultaneously.)

MR. O'CONNELL: What Steve's done is a little bit more sophisticated than what I -- I looked at just simply just the development security. What he's done is he's actually added in the bid deposit, he's added in the opportunity cost of the capital that he had to use for the bid deposit, and for the, the development security. So I think he's, he's doing a little bit more sophisticated additive analysis, which I did not do. So I think that's why his numbers is quite a bit larger than mine.

PANEL 1 MODERATOR ZAMINSKI: Thank you, Rick. Yeah, to put that a different way. A lot of what Rick has done is he's looked at the, the bid deposit stand-alone. What I've done is I've looked at the project life of these different elements of credit, and I've removed all of those elements and I put them back in, and I looked at the net effect.

So he's done a stand-alone, I've done an aggregate view.

MR. WAN: I, in my opinion, what this, this market is really about is the big players and the small players. The big players are the credit haves, and the small players are the have-nots. So the big players, we have several here, whether they're FP&L or, I don't know if PPM is here today. They can easily post these credits with very, very low credit line fees. Minuscule numbers. So that's one end of the spectrum. The other end of the spectrum are the little guys, and I will agree they may have to essentially consider their credit posting to be their initial capital.

So, so I think we are not being very

clear by generalizing everyone in the same situation. That, that was my thinking.

MR. GRECO: But I think what you have to add to that, though, from, from a developer's perspective, is not only just the cost to the LOC, but you have to include, as suggested by Steve, the increased costs of your interest rates, because an underwriter is going to view some of those operating risks there as a higher risk. So when you're looking at the contract as an overall, you can't just say simply no matter what the size of your company, that the only cost is the LOC cost. There, there are several additive costs to that, because we've done a similar analysis to Steve, and Steve's numbers are in the ballpark.

It's, when I was looking at this chart, I kind of leaned over and, and said to him, I said, boy, these numbers look light. And he said, well, what do you mean? And I said well, it's just for the LOC, I agree. But when you add on the additive effect of finance-ability, interest rates, carrying costs, all those things add up to a significantly higher number.

MR. PIZARRO: Joe, I think that's fair and helpful. Let me just add, though, I think we're missing, we're missing a piece here, we're missing an angle. You've got to step back to what is the whole purpose for this stuff. And again, it's allowing customers to have some sense that when, you know, we sign a contract with you, that there's going to be performance in that contract. Is there a cost to that? Yes. And I think you guys are helping to triangulate on what that cost may be.

The other piece to this is what's the appropriate level of performance, and therefore the appropriate cost that customers should be taking on. That's why we've gone, and I think PG&E is doing the same, we've gone to asking you for different datapoints. For example, in the renewables, asking for price points at three, six, 12 months worth of security on the operating collateral side. Because, quite frankly, again, I'm not smart enough to know what the right level is until I ask the market, and the market comes back and tells me well, if you want this much, you're going to pay this much for it. And if you want this much more, you're going to pay this much more for it. And then there's a judgment call that, you know, the customers are going to need to make in terms of what they want in their portfolios.

Now, once you have that out there and you kind of set up the expectations of what are some of the price points that we're looking for, then the question for us is, as we turn to the market, who can deliver the most value at the least cost for our customers. And that's when we get back to the whole question that Steve was bringing up appropriately of, you know, how do these requirements affect large versus small developers.

At some point you have to ask what is the objective, what should the objective function be given that we do still live in a capital society, right, and what we're doing is we're letting capital find the most efficient way to serve customer needs. If at the end of the day that means that you need some teaming up between small developers and large developers, where a small developer can still be an important part of the value chain, and take wind, for example, my understanding of the industry is that you do have a range of small developers out there who are just a heck of a lot closer to local siting and permitting issues, they know where their resources are, they can help in the early stages and, and really get a project launched.

If they're faced, though, with their financial structure not allowing them to put together the best possible bid, you know, or a bid that might not be able to compete with somebody with a larger and more stable balance sheet, then I think that's where capitalism says money will find efficient ways to deploy itself, and that will probably lead to teaming opportunities between large and small so that you can create different packages so that at the end of the day can compete better in RFOs, so that customers can then get their best value for their money.

I mean, that's -- so I, I get, I get concerned when we approach this from the angle of how do we make the world okay for small developers. We want to make sure we make the world fair for everyone, but there are a lot of financial players around this table and around this room who I think can bring some significant wherewithal to making the market more efficient for all of us and ultimately delivering more value. And, you know, I want to see creativity out there, and I want to see those teaming opportunities.

MR. GRECO: Well, I think overall, whether large or small, Pedro, the key is what is the reasonableness for the overall risk profile. you mention that you wanted performance. Any developer is incentivized to perform for a couple of different reasons.

One, we don't perform, we don't get paid. Number two, in order for us to finance the projects, there's criteria within the financing that suggests we have to have an operational profile outside of what the PPA requires. So if we're not meeting coverage ratios, et cetera, we're jeopardizing the project, we're jeopardizing step-in rights. Whether you're a large or a small.

So when you're looking at the overall risk, we need to come up to a balance. And I applaud that you've taken an approach of now looking at caps and, and a reasonableness to the collateral requirements, because in the past when you were looking at mark-to-market, the one thing lenders don't like is significant variability. So, and, and we appreciate that very much. And I think that's going towards the right direction.

Now the question is what level makes sense, and when you're attaching to projects, and I understand you're going after the markets, and understanding that. And whether you're large or small, in any event there's a cross back on the ratepayer. And all most developers are suggesting is we need to have some sort of reasonableness to the risk profile, and a sharing, and that the utilities are going to share some. And so we, for example, you had mentioned the, the crisis before. And many people wanted to leave contracts because they felt they had better opportunity markets.

Well, many stayed and produced while not being paid when the utilities' collateral was extremely low. So we've got to look at that, as well, that most of the developers here who had contracts stayed in the market. Yes, there are a few exceptions, and we don't want the ratepayers to know the developers to have to pay for those few exceptions. That's the bottom line.

MR. PIZARRO: Yeah, and Joe, I agree with what you're saying, and let's face it. Those exceptions drive our picture of what the risk is, and unfortunately, that, that creates these conditions for the market as a whole. Let's step a way back. I think it is nuts that as you look across the entire U.S. electric industry, you have billions of dollars tied up in capital that's basically not performing. You have billions of dollars across the country tied up to hold up collateral, you know, guarantees.

That, what a horrible use of capital. It's just sitting there just in case. But unfortunately it's the market we have. You know, I, I think Commissioner Bohn mentioned the, the role of the bankruptcy court in all of this. Well, again, as Fong mentioned, PG&E and SCE and, and CDWR are embroiled right now in the legal battle of bankruptcy court in the case of the Calpine bankruptcy, you know. It may be that if you got the bankruptcy court, or maybe even the Supreme Court, affirming that there is something special about some of these power contracts that are serving load, that allows you some greater security for bankruptcy.

I would expect that would free up a lot of those billions of dollars in capital, because it would take one of the big risks and it would significantly diminish it. And now we'd be looking at ensuring in some of the more general performance risk. But you know, that one alone, the bankruptcy risk issue, if you took that one out of the equation, I think you'd see a very different environment.

MR. GRECO: I agree with the Commissioner on that one. That's a wild card.

MR. PIZARRO: Yeah, it's a, it's a huge, it's a huge wild card. We're not, and therefore we can't bank on it and therefore we continue with the current market, you know, based approach. And again, we want to get signals from the market and want to price it out and then make some judgments about how much, you know, is worth -- you know, today, some people get the auto insurance of 500, $500 deductible, some get it with a $2,000 deductible. It depends on their position and what bids they're getting from insurance companies. That's an analogy to this.

CPUC COMMISSIONER BOHN: Pedro, let me just ask you a question. Would it be cheaper in your judgment if the Commission were to allow you to recover an insurance premium to cover all these risks? Would it be cheaper for the ratepayers and the citizens at all? Then you guys can, you guys can self-insure against a lot of these things if you chose to do it. That may not be the right answer, but it is an answer. Would that be cheaper economically, in your judgment?

MR. PIZARRO: We don't know yet, Commissioner, because we haven't seen the products out there or the costs. We, we're looking, and would certainly be open to it. I think Fong said earlier, at the end of the day what we're really looking for are electrons, not just financial mitigation. But we go to financial mitigation as second best, it could be that insurance pools might provide a creative approach.

There could be other approaches, you know. There could be third party financial intermediaries who could better manage that risk. You know, a large bank, I think their whole, their whole business system is around managing financial risk, and I'd like to see them, you know, being able to create some unique products and creative products and step in here, as well.

So I, I think insurance pools, you know, other intermediaries, those could provide solutions. But we have not seen them develop yet. I think we're early in the game.

UNDERSECRETARY DESMOND: Steve, I, I want to go maybe in a slightly different direction, I'm sorry, and get back to what I think jumped out here that was quite obvious regarding the difference between the intermittent resources such as wind and geothermal, and spend a little bit of time hearing from the panel members talk about whether or not you need to be looking at those credit requirements adjusted by the expected capacity factor. Because you're looking at geothermal rated at 40 megawatts, wind, and yet you can see the impact of the intermittent nature because you're holding it on a straight dollars per kW basis.

Is there any reason not to make that adjustment, considering you're still going to a mark-to-market perhaps on the back end to cover the difference in energy, all things being equal? I mean, why, why penalize wind unfairly, and I know it's not intentional, but is there not a reason to revisit that and say we can adjust it based on the expected capacity factor?

MR. PIZARRO: That's a live issue for us right now. And we did get that feedback when we heard -- held a workshop with renewables developers a few weeks ago. So we're, we're actually taking a look at that right now.

MR. WAN: We can do that, Joe. I, I think we can do that especially in the first two of the three stages I talked about, and in the first stage we are -- PG&E for renewables, we have already moved to the fixed flat fee concept, in terms of per month. So that takes in account, in account of the capacity factor you mentioned. The first two steps we have not done that, so far.

UNDERSECRETARY DESMOND: Thank you.

PANEL 1 MODERATOR ZAMINSKI: One, one other thought, and then Terry, I want to give you a chance to do that, too.

I, I think, Terry, you're really referring to the mark-to-market aspect. I, I think what we've heard here this morning is, you know, I, I think the utilities are faced with this really hard problem of trying to make sure they're covered in a dynamic situation of moving power prices in a very complex market, and they've come up with this mark-to-market concept as one way to get there. And I, it's like some of the others. It's a, it's a work in progress, it's a legitimate attempt to try and cover off the risk.

The challenge is that on an absolute basis, if you go to try to finance this as an independent, the bank says I don't know what that's going to be so I'm going to take the most conservative posture. And I'm going to withhold the whole thing, the worst case scenario, and you're going to have to reserve against that and I'm going to limit your debt capacity to the extent of the worst case scenario. And, and it has that sort of dampening effect on, on projects. And, and when you take that away, you replace that with more expensive equity.

And so as it relates to renewables, I, you know, it, it feels like that's, it's, maybe there's some other things that can be considered in the second panel this afternoon with respect to alternatives. I applaud Terry's consideration of step-in rights as a cost less alternative to ratepayers in the absence of a problem, and, but with those comments, Terry, you had a, something you'd like to add?

MS. FARRELLY: Well, one of the things I just wanted to say is just based upon meeting the California RPS, the requirements, and that a lot of these renewables are, are small, and that's true. But we're not going to be able to meet that, that goal with all small projects. I think we need to put together the portfolio of larger developers, smaller developers, and then we could have a weighted average cost of credit.

Also, we are going to be putting together proven technology portfolios as well as emerging technologies, and to the extent that there may be some ways to measure credit for wind projects based upon technology, I think that in order to get to where we want to be I think we have to put together a basket of opportunities, and maybe an insurance policy is one of them, as well. But it's -- and, as we throw in non-renewables into this portfolio mix, not one aspect is going to fit all of these, and so to the extent that we can come up with something that is, is somewhat a little bit formulaic, so we all know it's -- how, how it's going to work.

But to really take a look at the individual entities and put something together that makes sense for the seller and makes sense for the customer, I think, I think that would be our best path to take.

MR. WAN: Steve, can I respond to your

question earlier? We, what I want to say is a couple of points.

Number one is that mark-to-market as a methodology has been around in the electricity trading market for over ten years. It is not an exact science, but there is a generally adopted practice. People can settle on a contract and settle on collateral. Even regarding very difficult compound options.

But what I want to point out is that Pedro's chart was really important. This business has changed quite a bit. It showed the first stage when we had the QF contracts. And all those were special purpose entities, essentially. And then we went through the stage of very large trading companies in which credit was not a problem. And, and so everyone went toward the mark-to-market uncap posting as well as damages. And it appears that we are going back to a world where all the projects I'm signing, I don't know about Pedro and Terry, whether renewable or conventional, they're all special purpose entities. And that's why it leads to the problem you talked about earlier, which, where they're equity investors or banks, they don't like the unlimited cap. And we are trying to move to address that.

So I just, I just wanted to make sure there's -- we've gone through an evolution, we're no longer in that middle stage.

PANEL 1 MODERATOR ZAMINSKI: I think you guys have done a great job of applying a cap. My point was not that it's unlimited, but rather the bank looks and says okay, I don't know what it's going to be, I'm just going to assume it's the worst case scenario, which is the cap. So --

CPUC COMMISSIONER BOHN: Let me, let me just interrupt for a second. I, I think we, we have a very -- I think it's important that we, we recognize that big and rich is always better than poor and small. That's just a fact of life. Capital, capital capacity is something that is a competitive instrument.

I think we need to distinguish, as, as -- in this discussion and as policy makers, if we want to for some reason encourage smaller developers. That may well be a policy issue. But I, I think it is probably unreasonable to expect the utilities to somehow go out and, and farm and decide what they're going to do in this sense without some kind of explicit sort of policy direction. Their job is to deliver electricity.

And we think, as a, as a state and as a, as most of us I think here on the dais, think renewables are a good thing. But nonetheless, at the end of the day the lights go on or off with these people delivering electricity. So I think we need to distinguish the inherent difference between small developers and big developers, simply as a -- in the competitive context.

PANEL 1 MODERATOR ZAMINSKI: That's a great point.

MR. SEYMOUR: Steve, I'd like to address one of the points you brought up a little earlier, also. You, you talked about the doubling down of risk during the development phase.

That increase in risk, at least for a renewables project for wind as we look at it, doesn't really get us anything. Because we're exposed, we're tremendously exposed during the development process, we're putting a lot of capital at risk, to the permitting process in California, which as everybody knows is, is not a sure thing, to wind, ongoing wind evaluation, to, to equipment pricing. We live in a, in a world where equipment pricing from the vendors is extremely volatile.

Those are all risks that we bear, and that's our, that's our business, and that's our industry. If we are unable to finish development of a project because we're not able to complete permitting or there's some other problem that comes up, we lose all of that money that's invested to date. It's just sunk, it's gone. If I also have a bid deposit that's down or a development deposit that's down that I lose as well, I've gotten, I, I get very little value for that.

So our, our response to that has been we are not participating in the RFOs right now. We don't have a project that's ready to go for '07 that's not under contract, and we'll hold off. When we have a project that's ready to go or in the development phase, when we've nailed down those risks, then we'll come in and we'll talk to you.

And we think that's the responsible prudent approach, given that there's not a tremendous amount of value for that additional risk capital. But when I've talked with your staff about that, they seem surprised. They seem surprised that we wouldn't put in a bid, and we just point out that we still have exposure, we still have costs, and until we can nail down those additional risks we don't see the value in taking on and putting up additional money that we would just simply lose if, if we can't get a permit or, or some other eventuality occurs.

PANEL 1 MODERATOR ZAMINSKI: Thanks, John.

Kevin, you had a comment?

MR. McSPADDEN: Yeah. I'd just like to comment on, or agree that the mark-to-market approach has been around for quite a while, but it's been around in the context of wholesale type transactions, and it really doesn't represent, you know, the types of transactions that we're talking about. The mark-to-market approach came out of the EEI form contract, which is a, you know, wholesale type contract. And if you look at it, it's basically like trying to fit a square peg in a round hole. It just doesn't work for developers in a lot of ways, particularly with respect to security.

I think there needs to be, you know, an

evaluation of the risk. We've identified the risk, but there's a number of mitigants out there, as well. You have, you know, lender backstop on these projects, you have a project that's being dealt significant capital that's being devoted to these projects.

So I think that, you know, in this context, you know, we've identified the risk, but I think there's a number of mitigants that, you know, you particularly need to consider with the development of a project, and not just strictly apply a, a mark-to-market type of approach.

MS. FARRELLY: Just a question. So are you saying that mark-to-market wouldn't work for PPAs?

MR. McSPADDEN: I think it, mark-to-market really doesn't work because of the fluctuations. I think you need, there needs to be some sort of negotiation on the type of performance security that, that you're, you're willing to discuss. But I think in that context, I think the utilities really haven't considered a lot of the mitigants in these types of negotiations, and I think perhaps if they had some sort of guidance from the Public Utility

Commission as to, you know, what types of mitigants they should consider in, in setting the performance security, I think that would be, be helpful in that context.

So I think it would, would really help, you know, the negotiations in trying to, you know, arrive at a, at an appropriate performance security amount.

MR. WAN: I can see where you're coming from, but can we talk a little bit about how the industry has changed to lead you to want this type of structure? I mean, what we used to have is major merchant generators developing big merchant plants, they have a trading arm with a strong balance sheet, and when we buy power we don't necessarily buy it from a particular plant or a particular LLC. And there is a lot of transfer pricing within a Calpine, a Mirant, a Dynergy, a Duke, Williams. I can go on and on. That, that was a trading model. And you're right, and that's how mark-to-market worked.

But what we have today is that that's no longer the model we see. Everybody who's showing up at our doors wants to propose a special purpose entity and sign a contract with us only with that special purpose entity. And there's a reason why you guys may want to do that. You guys can talk a little bit about it. But we see something significantly different in terms of who's showing up in front of us as a counterparty. A big firm with lots of power plants in its portfolio and selling it versus a special purpose entity coming to us and say give me a contract, 20 years, then they take the contract, leverage it up, monetize it by selling it to other private equities.

It, the risk and returns for us that we see in this contract has changed quite a bit.

MR. McSPADDEN: Uh-huh.

MR. WAN: And maybe you guys can tell us as to why this is better for you guys. Because some of the panel, the panelists up here obviously represent firms who can -- is capable of doing the previous model, but is choosing not to.

MR. McSPADDEN: Yeah. Well, I guess as we get into the discussion more today I'd like to, you know, identify what I see as some of the mitigants to the risk that you're pointing out, and then also alternatives to, you know, strictly putting up a letter of credit guarantee, some of the things that might reduce the amount of security that, that could be required.

MR. TORMEY: If I may, I guess to your point, Fong. You might have been trading with the Mirants of the world kind of thing, but from those who are developing projects, when we signed our contract with Mirant, by and large, as I think Kevin would say and most people would agree over here, we were not getting, signing up a mark-to-market collateral. So when Mirant signed a contract with us, or Exalon, or Williams, we put up a, a fairly small LC. I say fairly small in relation to some of the, the credit requirements that we've seen in some of the RFOs.

And so that, that, it facilitated financing. It was sort of a, a liquidity amount. But, you know, I think the point has been made several times that, that from a financing perspective, mark-to-market is very difficult for us if we plan on financing. The lenders don't like the variability.

I guess also I'd just throw out there that, that we need to keep in mind when we talk about the off-takers being covered, there's a difference between liability and having all of the risk completely collateralized. And I understand where you guys are coming from, but it's obviously better to have a bigger cash collateral or, or liquid collateral in the form of an LC to cover off the risk, and you do it on the mark-to-market basis and there's very little risk there then.

But, you know, one of the concerns that's been stated is that the, the project simply walks out and starts selling for a higher price somewhere else, that's a healthy project. And they breached, their liability still is to cover you, and you are completely covered, I guess I would say.

MR. SALTMARSH: A quick question. Particularly maybe to you, Fong, but to anyone. When you were discussing your incentive and as I understood it, your incentives are at different points during this to ensure that you have someone who was, was real and capable of, of going forward with the project, that they're really committed to go forward, and then that they were performing once you had the project in place over the life of it.

Under, as you've described, the, the evolution of industry models, if you, if you were dealing with a very large enterprise and you had a contract that was essentially backed by the full faith and credit of that enterprise, the, the contractual damages would seem to me to be the primary incentive for them to continue delivering over the life of it, rather than, than some instrument they were going to forfeit, that may be valuable, but probably much less.

We have been some, somewhat concerned, as I think you have, watching the proliferation of, of industry structures in which you have an enterprise where perhaps the contract is their only asset, and if the contract becomes un-economic there is the, the bankruptcy cloud that they may be able to escape performance. But if there's one thing that, you know, has sort of become my adage over the last ten years, it's that on average customers always pay.

And so as I hear this last discussion, what I'm really wondering is, you know, not whether you have an irrational response to the structure of entities you see coming in, but if we have a higher customer cost really, you know, as a result of the special purpose entity model. I mean, if, if we have a, just, if we're just dealing with a business model that is likely to produce rationally a higher set of costs that customers are going to bear, because it has a higher risk profile on them.

I don't know if you --

MR. WAN: I think you got it right. That's how I -- can you repeat your exact question to make sure I got it?

MR. PIZARRO: Well, yeah, I, I think I understand. I mean, we, we're, I think where you're going is by having individual utilities looking at credit requirements or adding some net cost on top of just, call it the straight cost of power, are customers ending up paying more than if they just, they did not demand the same sort of credit or performance assurance and then took the occasional hit. Is that a way to re-state your question?

MR. SALTMARSH: No matter what we -- no matter what we did as a policy in credit instruments, you're going to have contracts that say there's a, there's a penalty for non-performance, and that penalty is going to be replacement cost, or maybe more. So if, if your contract was with all of FPL, wherever it exists in the world, and it was backing your contract, you know, plus a credit instrument, I think you would agree that the, that the primary recourse that you had for non-performance is that contract guarantee.

And so to the extent you're dealing with a special purpose, a whole series of special purpose entities that don't have more than themselves and whatever their capitalization is behind it, you know, are we having to absorb this cost by consumers for that structural model, and are we, you know, are we getting anything. I don't know that we're escaping risk from elsewhere in the company by dealing with this, this special --

MR. WAN: Well, I, I think we are getting something, Eric. What we -- you nailed it right in terms of large trading companies. The objective of, of the IOUs to ask them to post a collateral is to make them indifferent between performance with us or selling to somebody else. So that, we don't really want their money. We want their power, we want to make sure they are indifferent in their choices.

And then when you come over here to all these projects, especially when we're trying to retire these old units in the marketplace in California, and we have thousands and thousands of megawatts also the utilities have to build, I think we would like to be very responsible and to make sure they show up on time, they show up reliably, and the same thing can be said about renewables. We want to make sure we can meet the state's goals. So if we have contracts with no teeth, we struggle with how to do that.

MR. SALTMARSH: Well, I don't think it's the terms of the contracts. You have, you know, an enterprise at the table that I haven't looked in a long time, but if I remember the terms of their non-renewable contract with the state, I think, you know, failure to deliver during certain key hours imposes a, you know, two times replacement cost penalty.

So, so the contract terms may have strong teeth as long as there's, you know, an enterprise to go after who could be subject to contractual damage.

MR. PIZARRO: Yeah. You, you need an enterprise to go after, and don't forget these special purpose entities cut two ways; right? Because I think we're focusing on the small special purpose entity that only has the contract as an asset. The flip side is, remember, the special purpose entities can provide also protection in the other direction. If you have a contract that is with a larger entity, the SBE can then help to insulate the particular project from defaults or failures elsewhere in the corporation. So there's, you know, there's a two-way jurisdictionality to this.

I, I think, going back, though, to the, what I thought was a really good question that I thought I heard you asking, which was at the end of the day are customers who always pay -- and I agree with you, ultimately all that money comes from customers -- are they better off with these contract by contract -- provisions or are you better off taking a look at it, you know, are you really creating value for customers in that perspective.

I guess one way that, that I would answer that is yes, it is important and there is value and the individual customers are going in from that because as large as Fong's portfolio, or my portfolios, or Terry's portfolio may be, these portfolios are still small relative to the, to the rest of the market.

And so, you know, we're talking about a number of counterparties, not, not the whole market that we are insuring against. We're insuring with -- we're looking for performance assurance with the counterparties with whom we've signed contracts. And so this, again, boils down to the analogy of the insurance premium for your car. You know, the reason I buy car insurance is so that I can insure against my car getting hit. From a societal perspective you might ask well, am I -- is society really better off having individual customers buying insurance, or should you pull it all together and, you know, it'll all work out and you can actually take out transaction costs, and you can actually end up with a lower societal cost solution.

You might be able to, but we're not there today in power, and we need to be providing the protection for the bulk of contracts that we have, and the only way that we, the only tool we have today is through these sort of protections, and the credit and collateral, et cetera, and other performance assurance, with specific individual contracts.

You know, if, if we see pools develop in the future, again, I think we would be thrilled to look at that, if it works.

MR. SALTMARSH: On behalf of, you know, sort of California policy-making, you may not very much be able to influence, you know, who, who comes to answer your RFP. But, you know, my, some part of my mind is asking what if everybody up here is right? What, what if you have put the rational incentives on what you're seeing come in, and what if the consequence of that is ten percent higher, you know, capital costs that are borne by consumers, you know, is there a way that we could influence the market structure to have some slightly different enterprise model come in that doesn't require rationally ten percent to be imposed on it.

MR. WAN: Eric, I think the previous --

MR. SALTMARSH: And that's basically my time.

MR. WAN: Yeah. Eric, the previous business model actually did not have a high cost to collateral. That was what we're, I was trying to say. A company with a very strong balance sheet, a very large company that we used to see, was able to have a line of credit, and John knows this probably better than all of us in terms of how cheap the line of credit could be and what we have done as the industry has evolved and credit has become more costly because of the changing industry.

Can we turn it back? I don't know. The previous model did not have a high cost of credit.

CPUC COMMISSIONER BOHN: Can I ask just, interrupt just for a second?

I'm interested in your, your comment about seeing special purpose vehicles coming in. Is that, is that common now? I mean, everybody's using the special purpose vehicle, is that sort of the structure of what you are seeing in the responses?

PANEL 1 MODERATOR ZAMINSKI: Commissioner Bohn, the, I think, correct me if I'm wrong, but what Fong and, and Pedro are referring to is a non-recourse vehicle. You can't really go past that entity's assets. And it's a protective tool used by developers to insulate their bet to the substance of, of that special purpose entity. And, and so, as opposed -- and, and correct me if I go wrong here, but I, I think the idea is that before, when the merchant model was out there, which the market seems to have disproven as a business model, there was more cross-collaterization amongst assets and the company's balance sheet, and, and you could, you could conclude that there was more to reach to if something went wrong, whereas in these single purpose entities you, you've got the plant, and it either performs or it doesn't, and its parent either performs or it doesn't.

And, you know, one, one tool, and this walks the dangerous line of getting into Panel Number 2 of alternatives, but is, is what, what Terry is, is suggesting and has been used in the past here in California and elsewhere, is the concept that the utility can take the plant if the parent stops performing. That's very helpful if it's the parent problem. It's less helpful if it's the plant problem.

But it, it is, in fact, like what's being proposed here. It's an imperfect solution to a what if. And, and, but the difference, the fundamental difference is it doesn't cost the ratepayer anything.

CPUC COMMISSIONER BOHN: Yeah. I, I

understand the, the single purpose entity process. My question really is, A, is that the structure that is being offered in all, in response to all of the RFOs, and Pedro's right, it does clearly cut both ways. It doesn't, without step-in rights or something, essentially you're just sort of stuck with it if it doesn't work.

My question is, is that all that is being offered in response to the RFOs now? Because it, it makes a lot more sense to have collateral requirements in that situation than it does, to your point earlier, that you actually got a company stepping up and saying I've got a big balance sheet, I've got a whole staff of engineers, and so forth.

PANEL 1 MODERATOR ZAMINSKI: I would defer to -- yeah, that --

CPUC COMMISSIONER BOHN: That's all you're saying.

MR. LUMSDEN: Yeah. Frankly, it's, it's always been the, the model, because it's a project finance model. And, you know, we, we saw SPEs with QF contracts, and we see SSBs now with, with the RFPs.

MR. WAN: Tom, I think in the middle

stage that I was talking about --

MR. LUMSDEN: Yes, you're right. There was, there was a stage where we essentially had power marketers that were contracting with independents.

MR. WAN: Yes.

MR. LUMSDEN: That's essentially marshalling the power to contract with the IOUs for sale.

MR. WAN: That's right.

MR. LUMSDEN: You were, you are now realizing we're assuming significant risks for performance by those power marketers that we weren't' really recognizing the risk.

MR. WAN: I think -- I don't think that's the way I would've characterized that. I think the utilities are fully willing to pay any damages if we don't perform. All we want, on the same mark-to-market calculation methodology, all we want is the other side to have the same. And the concept behind that is really to make each party indifferent from not performing. And what we -- this discussion's going around in circles about how it doesn't work for special purpose entities, how it's too expensive. It's really coming back to we were trying to find the indifference point to make sure we get that power for our customers.

MR. LUMSDEN: I agree with you, Fong. I think the, the essence that, the hurdle we all have trouble trying to overcome is the risk of an SPE bankruptcy. And their contract rejection and whether FERC and the Supreme Court and everything else will ratify that rejection or allow you to essentially uphold your rights to that contract. I think that's the real essence and I haven't figured out the solution, because I think all other stages of development, as Steve was pointing out, you're really having to double, double down your bet by putting up contract, putting up collateral up front, while at the same time you're essentially bleeding out your up front equity because the equity is what goes in first on the development stage until you can prove up your permitting and the engineering and technology, and qualify for project finance.

And I think that there's, there's ways, you know, it's, it's easy to ask for people to put up cash for collateral. That's the easiest thing, and essentially I believe that there is a significant cost that's being charged across the board, as Commissioner Bohn suggested, that, you know, there, there is a, a charge that we in California are paying in order to have this assurance of performance through the RFP process that we're seeing now.

But I think we need -- you could be much more creative. The rating agencies, those of us that go out and have to do evaluations on power plants, we go in and do the risk assessment of performance of plants, either at the early development stage, during construction, or during operation. And, you know, we have to essentially come up and measure the risks, and there's probably a hundred different items you have to check off to determine, as Kevin was pointing out, have we mitigated the risks or not. What could happen. And there's ways that, that lenders themselves provide themselves backstop and protection to step in and take over and preserve the contract rights, and preserve the asset value, just in case something goes wrong.

And it seems to me that's something that we could be creative about in terms of trying to structure something with the IOUs on these contracts.

UNDERSECRETARY DESMOND: Steve --

MR. GRECO: And continue to be mindful -- I'm sorry -- that the RFO process was a process that was created to increase the competitive nature of the bids. I mean, so there is value in that, too, so there's kind of an offset between I think what we're talking about here, and it goes back to what was suggested before, is what's the balance of risk. There's got to be some balance amongst developers, some amongst the IOUs, which, in a sense, is borne, yes, by the ratepayer, but the bottom line is what is a reasonable measure to get there.

The other environment, in terms of the -- when we were looking at the market players, there were just a few players there which I don't think gave you the competitive nature that you do have by having these RFO processes the way they are now. Yes, there are issues of bankruptcy that are brought up there, but overall, I think you're getting, from a portfolio perspective, a more balanced portfolio.

So there are some isolated issues potentially, but overall, you're balancing the portfolio in a better perspective.

CPUC COMMISSIONER BOHN: Thank you, Jeff.

UNDERSECRETARY DESMOND: Steve, I just want to acknowledge we have a scheduled break at noontime on the agenda. We still have the PPA interconnection issues. I know there are some folks in the audience that want to ask some questions, so I'm asking you, as Moderator, are we going to take this issue up now or when we come back, or how would you like just to --

PANEL 1 MODERATOR ZAMINSKI: Well, I was, I don't want to be the person between you and lunch. But I would suggest, with the hope of getting through what is a, a very optimistic and aggressive schedule, that we ask Tom if, if he could run us through his slides in the next ten minutes or so, and we'll hopefully be able to wrap it up with just being a few minutes past noon.

MR. FRENCH: Hello. I'm Tom French, with the California ISO, and I'm going to talk quickly, I'll try to get through this quickly, through the timeline and some of the issues associated with the costs associated with interconnections and the interconnection study process.

As of June 23rd, or just recently, last Friday, we became responsible primarily to the interconnection customers for interconnection studies and managing the process through that from basically application received through the generator interconnection agreement.

And I want to point out that this slide in no way stands alone, and it needs a lot of explanation. Basically, what the timeline shows is, is generally the maximum allowed timelines for various portions of the interconnection study process. Application received. Something new in the last year or so is the scoping meeting and the feasibility study. That was implemented and intended to provide developers with information faster than they were able to get information previously.

Typically, they went right into a system impact study and facility study, and those types of studies take a much longer period of time to complete in order to provide cost information, and so on, to customers.

I want to point out that, that this timeline goes out to 544 days, and that seems like an awful long period of time. We do have projects and developers that get through the process in months, maybe three to six months, and we do have developers that take much longer than 544 days, and so this is not intended to represent an absolute, but it is generally along the lines of the maximum tariff related timelines in order to perform certain portions of the study process.

Below, you see the typical costs associated with interconnection studies. Again, the feasibility study is a fairly low cost study, intended to provide the developer a good faith estimate of costs to interconnect. And so that, that comes, if you take the maximum timeframe, roughly out 174 days, but I do want to point out again, depending upon the nature of the project, it could go much faster than this, and depending upon the project and other issues associated with maybe optional studies or re-studies, it could take longer than this.

The customer generally pays the actual costs for studies along the way for each one of these studies, except for the facility study. There's a non-binding good faith estimate of cost provided, and schedule timeline in order to interconnect that particular project.

Firm costs are typically determined after the facility study is complete, and I'll talk a little bit more about that coming up. Interconnection study costs typically to get through that process of interconnection studies is 100 to $250,000, fairly lost cost compared to all the costs we talked about a little bit earlier today. The non-refundable costs are typically those study costs, as well as the direct interconnection facilities. If there are network upgrades required, reliability network upgrades or delivery network upgrades, there's a variety of methodologies to refund those costs over a five-year period, typically in increments of 20 percent over those, that five-year period.

Some of the costs and risks. There's a, there's a whole gamut of potential exposure, and I want to, again, this slide needs a lot of explanation, as well. But typically, the, the developer is responsible for the incremental costs of connecting their particular project based on their queue position, so they're basically studied. If a project comes in and has a 2010 interconnection date, those projects that are, have applied earlier are considered to be higher in the queue, are modeled along with that particular new project, and the incremental costs if there's any upgrades associated with that project associated with this queue position are the costs directly associated with that particular project.

That, that may be the only cost, and it may not be. And I say that because if a project is located in an area where there's plenty of transmission capacity and there are no other projects in that area, the risk of other projects impacting that particular project is almost nothing. And so the costs typically don't change over the course of time.

On the other end of the spectrum, if we have projects that are all locating in the same area and there's a limited amount of transmission capacity, there's exposure to that customer uncertainty associated with the cost because the cost could change, depending upon if projects drop out that were higher in the queue.

I'll just explain a few of these, a few of these components. The future year analysis is just that incremental cost to interconnect that project based on the, the queue position. What typically occurs, however, is that a project may apply and get a queue position and have a commercial operation date of 2010. Another project comes in after that, applies, maybe has a interconnection date of 2007. That type of analysis needs to basically, if we want to interconnection that customer in 2007, we look at the system based on that 2010 interconnection, that first project in the queue. If there are upgrades associated with that the costs are allocated to that 2010 customer.

However, if that customer drops out that queue position where the interconnection was 2010, and there happen to be upgrades associated with that that allowed for the 2007 project to interconnect without upgrades, there's a possibility that that customer could be exposed to the upgrades associated with that 2010 project.

And in the case where there's a number of these concentrated in an area, we have to look at all the potential combinations that could occur, and there may be a, there may be a great deal of exposure, and there may not. But it's a, a certain amount of uncertainty.

In terms of maximum funding exposure, FERC ordered basically in its Order 2003, that the transmission provider to provide an estimate of the interconnection's maximum possible funding exposure. And as I, just in summary, that could be just the direct interconnection facility cost if it's the only project in the region and there's plenty of transmission capacity, or it could be quite a bit more than the cost just allocated based on that customer's queue position.

And so there's two ends of the spectrum. We're saying in some cases customers move through the process in a very short period of time, maybe three to six months, with no cost uncertainty associated with their interconnection. We're also saying things like the Tehachapi area, where there's a large number of projects and limited transmission capacity, so there's a great deal of exposure or uncertainty associated with those interconnection projects.

The project economics are sometimes estimated before all interconnection costs are known. And that could largely be the case because of what I just talked about, or other reasons. And interconnection costs can change significantly over time, depending upon how projects interact with each other based on their queue position and available transmission capacity.

Again, depending upon how the projects are staged over time, 2006 to 2010 or 2011, cost exposures may or may not materialize because they are dependent on the actions and decisions of other, other developers over time. And the issue exists whether a standard queuing methodology process is used or whether a clustering process is used.

PANEL 1 MODERATOR ZAMINSKI: Try to wrap this up so we can eat lunch.

MR. KING: Steve, if I could make a few observations. I've sat up here quietly and I'll try not to delay us from lunch. But those of you who know me, I've sat here for two and a half hours and haven't said anything, are probably aghast.

A couple of observations, and I'll try and be brief. One is that capital doesn't necessarily equal credit, so looking at some of the structures and tax structures that are likely to be attached to some of these projects, wind in particular, but also geothermal, I have capital, I don't necessarily have credit as a private equity fund. We typically do things on a one off basis and investment, and most things are cash led.

So if you are looking at deposits or other things, at least for a period of time, these have to be treated as capital outlays. So they come with a price, and they come with a fairly high price. It's obviously not true if you are a, a Mirant or somebody in the, in the -- well, forget Mirant for now, but --

(Laughter.)

MR. KING: But it's certainly true that for a period of time you're talking about a very high cost of capital, and so that does translate into, into projects and for some of the structures that will go on, as well. You may not see any, any structures. It may all be debt on the one or two levels up, so it'll be back-levered, so you don't actually see debt. You wouldn't necessarily see the types of project level credit requirements that would enable you to issue an LC at that level.

Now, if you're doing a structure like that, you've probably got somebody on a tax structure, on a tax basis that can provide an LC, so you've probably got something at that stage. But that is generally a post-completion issue, and you won't know until you get there, so you still have timing effects.

The other observation is that small developers doesn't equal small projects. I think there's been an equation that small developers are bringing small projects to the table, and that's, that's definitely not true. I don't know, maybe that was just my impression from this particular meeting, but some of the smaller developers I've seen have some of the, the greatest ambitions in terms of size of projects, so encouraging these guys to, to stay in the game, not sell themselves out too early to, to some of us -- by the way, thank you -- but, you know, from that point of view, I think -- I'm not trying to be altruistic, but along with Steve, I think we have to make sure that we keep the incentive up for the small developers.

Another observation, quickly, on, I just have to mention this on the interconnection side. I've never, I haven't seen anybody who's got it done in three to six months. My experience is at the end of the day, we'll probably get our project interconnected in about 12 months, and I think that's remarkable considering that it already exists, it's already interconnected and the line's hot. So, other than that, 12 months isn't so bad.

The, the one issue in terms of the, the overall credit structure, what you pay, how much the deposits are, what the impact is, and the need for performance security on an individual project basis. My take on this, I think, and maybe I'm just reading this into John Bohn's comments, but I think that, that the utilities themselves are probably in a much better position to self-insure, or put some sort of structure in place to address this, rather than, rather than the individual projects, subject to the CPUC letting them, I think is the key.

I love the rental analysis, by the way. I have had some of my deposits not returned, but that was college.

(Laughter.)

MR. KING: By the way, what it doesn't say in my, in my bio is I have an undergraduate degree from UC Santa Cruz, and my graduate degree from Berkeley.

The, I think the rental agreement is, is interesting because it's exactly backwards. The landlord is providing services and the renter is paying, and the renter provides the deposit as a security against non-payment. If the landlord doesn't perform, then the renter withholds payment. That's fine. But it seems to me that if you require every service provider, i.e., the landlord, to put up a deposit to you because you're afraid of the building going condo, then something's going to go wrong here, and you're going to end up paying too much, which I think is what we're starting to see, or what we're seeing in this.

So without getting into it, I think the idea of being able to self-insure, find a way to mitigate those risks gets an additional cost at the utility level, but find a way to balance that within everything else, rather than having every single project put up a, a total amount of security of six or 12 months revenues for, you know, their default, when you could create a pool, potentially. And now I'm getting into this afternoon's session.

But there's got to be easier way of dealing with it and a much less expensive way of tying up billions of dollars worth of capital.

PANEL 1 MODERATOR ZAMINSKI: Well, we'll have the opportunity this afternoon to deal with some of those issues, Tom. Thank you.

In the interest of time, let me see if I can wrap this up. In addition to the topics we've talked about I think there are some other topics that I would hope that would get air time at some point in the future, which I think are also very important.

As you think about scarcity and cost of new capital for California, I would point out that I think one of the things that many people acknowledged is that it's very difficult for a small developer, and I would point out two large developers who play a, a very big role nationally, I think it's profound that John of FPL here is, is saying no to California. I would point out the, the five operating projects that we purchased from a Fortune 100 company, they are taking their investment out of California and going elsewhere. And I'll leave you to think about why that is. I'm happy to talk offline.

There's another issue that we face as a developer of a sixth power project in California, and that is that the permitting process is, has sometimes been an opportunity for special interests to extract their pound of flesh. I know this is an important and a very sensitive topic to, to everyone in this room, and I would suggest that using the guise of environmental concerns to extract a pound of flesh is, is a very challenging thing for this group to consider and how they address that going forward.

It is a major concern for developers. It is a big component of why it's more expensive to build in California. And that's a politically sensitive topic, and one that I won't dare to go into here. But I, I think it's one that I would hope that would be considered for future discussion.

The last thing that's sort of near and dear to my heart is, is this, this notion that an RFO would be only for new metal. I, I would suggest to you that the operating plants that we own could sell and provide power to ratepayers more cheaply than building a new one. We were happy to do that. We couldn't do that because of the discrimination policy of only allowing four new metal in an RFO, and I think that's something that, you know, needs to be considered from an environmental perspective and efficiency perspective.

At the end of the day, the, the new plant we're building is, is just about a carbon copy of the plants that are in the ground already, has the same environmental profile, the same efficiency profile, and a cheaper cost of power. And I hope that we can talk about some of those things going forward.

And the last thing I'll put up is where I started, and, and that is this really does matter. This is a component of the overall puzzle. I think it's a very important one. I applaud the Commission for taking it on, and I very much appreciate the panel and their participation. It was the equivalent of hurting cats, and I thank you very much for your patience with me, and the audience, as well.

Thank you.

(Applause.)

UNDERSECRETARY DESMOND: I'd just like to remind everyone we're going to reconvene at 1:30 promptly. We have a very lengthy agenda this afternoon, and I'd like to thank the panelists for their contribution here this morning. Look forward to seeing everyone when they return.

(Thereupon, the luncheon recess was taken at 12:04 p.m.)

AFTERNOON SESSION

1:35 p.m.

UNDERSECRETARY DESMOND: I'd like to welcome everyone back to this afternoon's session. I think we'll have a lively discussion about the alternatives, after having had, I think, a very thorough discussion this morning about the issues surrounding the credit requirements and all the issues on generator contracting, PPAs, and some of the utility ownership risk allocation.

But before I do that, I just wanted to make a brief announcement, which is that on the table in the foyer there is a Notice of Committee Workshop on the Mid-Course Review of the Renewable Portfolio Standard Process, and that is scheduled for Thursday, July 6th, at 1:00 p.m., and we'll include both, again, Commissioner Bohn, as well as the IEPR Committee here, Chairman Jackie Pfannenstiel, Presiding Member, and Commissioner Geesman as Associate Member of the IEPR Committee. So that is Thursday, July 6th, on the Review of the Renewables Portfolio Standard Process.

With that, I'd like to ask that we rejoin. We still have people online, and we're about to begin our second topic area today.

Leading us in this discussion is going to be Gary Ackerman, at the Western Power Trading Forum. And Gary, I'm going to turn it over to you, and I think you had one holdover question from this morning that you wanted to address. So at this point, go right ahead.

PANEL 2 MODERATOR ACKERMAN: All right. Thank you, Joe.

Steven Kelly, you had a follow-up question from the first panel that you wanted to direct, and let's just not spend more than, let's say, five or so minutes on it.

MR. KELLY: I did want to make a comment on the --

PANEL 2 MODERATOR ACKERMAN: Is the microphone on? Green light? Yeah.

MR. KELLY: There we go. Okay. I did want to comment on some of the discussion I heard this morning on Panel 1, and then ask a question of the panelists that are still remaining her, and maybe Rick, who had put together the report. And, and my comment is feeding off some of the questions that Commissioner Bohn had raised regarding risk and risk allocation. And when I think of this problem, I think of there are basically risk elements in the way it's been kind of described in the report that was presented this morning, is there's the, the bid, you know, whether the bids are viable, and so forth. Then there's the development risk, and then the operational risk.

And when I think of it, I think of those risks being essentially the same as elements of risk for big and small generators for IPPs and IOUs. Those risk elements are always there, they don't go away. What we're really looking at is trying to allocate that risk properly and minimize that risk to consumers in order to get the best product to them.

But feeding off something I think Pedro said this morning, which struck me as interesting, that I think he mentioned that the exception seems to be driving the risk assessments, particularly here in California. And I, I think that that is one thing that we need to focus on, in terms of, of looking at credit and collateral issues for California, whether that is actually happening.

One example was the threat of a generator walking away from a contract, for example, and, and I'm not convinced that that threat is particularly real. Any generator that's got a 20-year contract today, I'd really be surprised if they'd walk away from that deal in order to hope they get another 20-year deal from somebody else. It just doesn't seem too viable for me.

During the energy crisis it was a different situation when we're looking at long-term PPAs tied back to direct, directly back to facilities. So I think we're in a slightly different environment.

But when I reviewed the study that Rick had done that attempted to compare California to other states, I was particularly struck by the comparison between the California IOUs and what's happening with Xcel. And in the cases for Xcel, not only the bid deposits were significantly lower than the California IOUs, but the operational risk was significantly lower in its matrices than what is present in the California IOUs, and I think that's a function of the fact that California used the mark-to-market kind of approach.

Now, interestingly, Xcel has higher development risks, which given that we're in California, I would've thought that would've been the inverse. But my question, then, is in light of that, and this is to Rick and any of the panelists that are still here, is what is the real effect of that difference? I mean, is Xcel, why is Xcel able to get significantly lower operational risk in their RFO process than California utilities.

And then, secondly, what is the effect of that for people that are actually developing projects and, and how do we overcome that.

MR. ACKERMAN: Okay. Steve, who do you want to answer that question first?

MR. KELLY: I, I ask it of the panelists, if they're still here. Maybe John Seymour could answer that.

MR. SEYMOUR: If I could take a shot at it. And I guess I'd like to, to start off by clarifying something I said this morning, and I've had a couple of people comment to me that FPL is not active in California.

We are active. We are not bidding into the RFOs at this time because of the exposure on the development, the development cost risks, but we are very active in the state of California. I just wanted to clarify that.

But frankly, the, the development risk costs, those bonds, you know, the, the -- we feel, we feel the cost and exposure of development in California is pricey enough, and we don't need to double-down on those costs.

The, the, Steve, I think on the, on the default risk, rather than clarifying, I'd like to clarify that a little bit. I think during the energy crisis there were problems with, with people walking away from, from contracts, from what I understand. But I think with very few exceptions, those were not generators with long-term contracts. The generators with long-term contracts continued to perform under those contracts even when they were not being paid. To my knowledge, the only generator that, that terminated the contract was one that was forced into bankruptcy themselves because they weren't being paid.

Now, I, I may not be aware of anybody else. If there are others, I'd like, you know, be happy to hear about it. But I don't think this is a, a major generator risk. I think there were certainly some market exposures that, that were a different question.

And then, in our experience elsewhere, we've not seen these kinds of, of credit requirements in other markets. The, there are a number of RFPs that have been, that we've participated in in a number of other states that have not had credit requirements either on the pre-development or pre-operational, or during the operational period that are anywhere in this range.

So that doesn't mean that these aren't appropriate, it doesn't mean that the risks aren't different, but, but I think that it's worth noting that this is, these numbers are significantly higher than what we've seen elsewhere in, in the country.

PANEL 2 MODERATOR ACKERMAN: Thank you, John. Other panelists? Pedro?

MR. PIZARRO: Yeah, just a couple of quick things. One, Steven, I guess you must've been referring only to the proposal fees, because I think it's interesting, if you take a look later in the same presentation, the development fees that Excel has area actually substantially higher than the ones listed here for PG&E. So, which I think really goes to the fact that you can't cherry pick a single number, like I think your question just said, and it really goes to different entities have a different mix, different balance, you know, across these different trade-off items.

So just, you know, and I don't know if you were just restricting your question to the proposal fees up above, or if you have looked at the development security. They --

MR. KELLY: Well, I was looking at the operational security matrix, particularly.

MR. PIZARRO: But, but again, that goes, that goes to, you know, different, different parties' fears of the risk at different stages of this. I guess, you know -- I'll stop there, because we'd probably end up re-hashing a lot of the things that we had earlier today.

PANEL 2 MODERATOR ACKERMAN: Good idea, let's not re-hash.

Who else wants to speak?

MR. GRECO: I think in other markets and, you know, for both renewable and non-renewable, what we've seen in the northeast areas and the east, the collateral requirement, just to support what John had suggested, are, are significantly less. One specific example, we're developing a 350 megawatt gas facility. Total collateral requirements are capped at about $9 million. A lot different than this market, if you look at the example that was put out by Chris. When, when you're adding all the numbers up for a 40 megawatt geothermal, they'd be north of that.

So I think those are just some similar examples that if there is a cap, it's a reasonable cap, it keeps people incentivized to run, put the appropriate collateral requirements on there, making sure the utilities are covered in that. If there is a default of, of any sort by the generator, that, you know, the, the ratepayers and/or just the, the shareholders are not the only ones at risk. There's, there's a common risk across the board.

So I think that's, that's what we're trying to choose.

PANEL 2 MODERATOR ACKERMAN: Any other panelists before we move on?

So we've heard from two developers and one utility. Two out of three developers think doing business in California is more expensive. That's a statistic. Now you can take what you say back. Are you satisfied, Steve, with that discussion, or do you want more? Okay. Very good.

This afternoon we're going to be talking on alternative approaches, and I thought what I would do in my early slides here, besides giving you a free advertisement of the Western Power Trading Forum, is identify some of the ground rules that I hope will make this discussion useful.

Now, we didn't get a lot of audience participation in, in the morning session. That's because you were asleep, so maybe by this afternoon you've had some lunch, and if you're twitching around in your chair I'll call on you to get up to the podium and speak. So, careful. Sit still.

Okay. Here we go. What, what do we want to accomplish today? In this panel, I've divided the 12 panelists up into two parts. Not the good guys and the bad guys, that was this morning. You must have missed that part. But I have six presentations, and six commenters. And the way we've divided it up is I've asked the presentations to reach out and think beyond, or outside the box, if you will. And that's, of course, what that picture there is supposed to help you indicate where are we on this whole thing. But where can we potentially go.

And that's not too easy to do, but we'll, we'll try and explore some idea and hopefully give you some things to think about, and maybe from a policy issue, too, you'll clarify what these presentations will mean to our discussion through your questions, I believe, because a lot of this topic matter might go by very quickly. There are no dumb questions. If you ask one, we'll tell you, but we don't think there are any. You've got to ask a lot of questions, I think, to make this panel really worth your while.

And the other role here of the other six members of our panel here today will be asking questions and comments. Now, for the most part, I hope they have seen the presentations. They have had a chance to review them. They might have some questions on their mind. I'm sure they'll have more as they listen to the presenters.

So that's pretty simple, right? Six presentations, six commenters, and here are the commenters. You've already met several of these people, or actually all of them, now that I think, except for Lad, at the very end there. And I couldn't help but noticing as I was looking at this and preparing the slide, that we have three developers here, Joe Greco, John Seymour, and, and John Tormey, from the developer side. And then we have Pedro from Edison, Fong Wan from PG&E, and different in this panel than earlier this morning, Lad Lorenz, from SDG&E.

Good, I always wanted to get a recorded message. Can we go on? All right.

And notice that the first names of the developers, it's John, John, and Joe, and then I picked out the first names for the utility guys, and it's Pedro, Fong, and Lad, you know. And I thought there's got to be a story here, but I can't figure out what it is.

(Laughter.)

PANEL 2 MODERATOR ACKERMAN: I think you have to give a bonus point to the utilities for cultural diversity, something like that.

Let me just speak briefly. You've met these people, but a sentence on each might be worthwhile.

Joe Greco, Vice President, Western Region of Caithness Energy, based in Reno, Nevada, responsible for asset management and expansion of their west coast geothermal and natural gas portfolio.

Pedro, Pedro Pizarro. I want to mention his arrest record and convictions, that's a separate topic that we'll talk about later. Pedro is a Senior Vice President of Power Procurement in Southern California Edison, and prior to that he was a senior manager at McKinsey and Company in Los Angeles, and he has a long list of very impressive degrees, I might add, in Chem Engineering from Harvard University and Caltech.

John Seymour, Executive Director, FPL Energy, and he's responsible for their wind energy development efforts in the western United States. He has a law degree from Columbia University Law School.

Fong Wan is Vice President, Energy Procurement at PG&E. He has a BS in Chemical Engineering from Columbia and an MBA in Finance from the University of Michigan.

John Tormey is Senior Counsel at Constellation Energy Group, and previously he was in the D.C. office of Chadbourne and Parke. He has a law degree with honors from George Washington University's Law School.

And Lad Lorenz, Vice President, California Regulatory Affairs for both SoCal Gas Company and San Diego Gas and Electric. He is based in San Francisco, and Mr. Lorenz' primary responsibility is for advocating for the utilities before the CPUC.

So that introduces the people who will be making the comments. And I want to give you an idea, and even our panelists -- my panelists, don't even know how I'm going to do this part, so listen closely. Here's how it's going to work.

We're going to be doing them in series of twos, because it's impossible to listen, especially at this level of detail, to six presentations and remember what the first one said, much less the second, third, or fourth, right? And you'd get lost. On the other hand, if we just chop it up into one at a time for comments and questions, we'd be here until next -- so we're not going to do that, either.

So what I thought would work better is if we split them up into twos. Even though the relationship here might be, well, only that they're trying to advance the discussion on alternative methods for reducing credit requirements and mitigating risk, that might be their strongest, so the first two speakers who will be starting off, Kevin McSpadden, who you've met this morning, and Partho Ghosh, who's here from Marsh and McLennan Securities. And I'll introduce them here in a second, and I'll, I'll just come back to the slide, I think, when I do that introduction.

But I want to give you ground rules, so let's just keep on going for a second. The next order would be John Buehler and Russell Read, and then I'll stop there and I'll ask our panelist of commenters to make any comments they wish. And by the way, commenters, if you have nothing to say, suggestion, don't say anything. But if you do have something to say or if you have a question, please bring it up. I think that would be good. Audience, same way. If you have something to say, a question to ask, do it after the respective speech or discussion that we have here.

And finally, we'll have Curtis Kebler and John Flory. Now, is it my understanding, Joe, that you want to take a break somewhere today? I mean, like by 8:00 p.m. tonight, was that where you had in mind?

UNDERSECRETARY DESMOND: I was hoping about 7:00 p.m. Gary, but --

MR. ACKERMAN: No, 3:00 o'clock, or do you care? Should I keep my eye on that?

UNDERSECRETARY DESMOND: Well, see how, see how the flow goes, but --

MR. ACKERMAN: Okay. If they start dropping like flies we'll know to take a break.

Great. That's, that's a great slide. I've always wondered what that meant. Okay. We'll forget the rest of this presentation.

Let's go then to Kevin McSpadden, and let me just tell you a thing or two about Mr. McSpadden. He is, as I said, with Milbank, Tweed in the global project finance area, where he's primarily -- primarily represents developers during the development stage of a project and negotiation of project contracts.

In the past year -- please turn those phones off, they just drive me nuts. Okay. In the past year he has negotiated ten renewable power purchase agreements with California's three

IOUs, so why don't you put your hands together and welcome Kevin to this podium.

(Applause.)

UNDERSECRETARY DESMOND: Gary, just as, just as a matter of procedure here, if, you know, all the speakers and the commenters could speak clearly into the microphone, because I know a number of people listening in had a difficult time earlier. So, that's all.

(Inaudible asides.)

MR. McSPADDEN: What I wanted to discuss today was basically some of the risk that, you know, I've identified in, in working with the California Investor Owned Utilities, and suggested risk mitigance and also alternative structures that could be used in lieu of the, of the security requirements that are currently required by the utilities.

This first slide, what I've tried to do is identify what I see as the, as the risk that both are, are told to me by the utilities and what I've sort of learned, as well. We've covered most of these this morning. The one thing that wasn't mentioned is the, in the development stage, to cover potential penalties for failure to meet RPS requirements. And I'll point that out, although in two slides I'll show you how that really isn't a risk.

So ideally, we should be placing a, we should be identifying the risk and then trying to place a value on those, on those risks. And based on that, the, the various security requirements should, should be set.

During the bid evaluation stage, what I've seen is that even though the, the bid deposits are not that significant, they do discourage that participation, there's less competition in the bid process. You know, it's mitigance that, that I see have the, the utilities have the least cost/best fit methodology which they apply to bids. They might have to evaluate more bids, but, but in the end I think that there's a benefit to competition. You know, in addition to the least cost/best fit methodology, you also have the CPUC oversight that's, that will be in place, as well.

So I guess overall I don't see the rationale for a, a bid deposit at this stage, particularly given here in California where we're trying to, you know, increase the, the renewables that are bidding into the, into the process.

During the development stage, I guess with, particularly with respect to the smaller developers, there is a significant impact to those that are required to put up the, the development stage security. The way it's currently structured by the utilities is that half is put up upon contract execution, and the other half is put up 30 days following the CPUC approval. And as was mentioned earlier, the, the significant milestone for the developer is at the, is when the construction financing is obtained.

You know, I recognize that there is a certain risk between the execution of the PPA and between the construction finance, but there are a number of mitigants in, in place that, that do mitigate this risk to the utility. You know, first of all, you know, I mentioned the, the penalties that, that are imposed on the, on the utility. And I'll get into the RPS penalties in a slide or two. But generally, there's, there is a mitigant.

There's a good faith exemption from the penalties under the RPS. If the, if the utility, you know, in good faith does enter into this, into these renewable contracts and for whatever reason the, the PPA or the project does not achieve commercial operation, you know, there are these good faith exemptions. They're not very well defined by the Public Utility Commission, so, you know, that would be a recommendation is that the Public Utility Commission could, you know, better define the good faith exemption under the RPS penalties, but that is, that is a potential mitigant.

Also, you know that once construction financing is obtained, you have the construction lender backstop as long as major equipment warranties. And I'll get into the alternative security structures in just one second. But as, as alternatives, you know, you do have step-in rights. There's, you know, certain concerns about step-in rights that I'll identify, as well. You have the subordinated security interest.

What we're also seeing, you know, during this time period is, you know, a direct assignment of, of a percentage of the buy-down under the turbine warranty. This is particularly, you know, we're seeing this more with, with wind type projects where, you know, they're agreeing to assign, directly assign a percent of the, of the buy-down payment.

And then, you know, the payment of daily delay liquidated damages, you know, is one of the, one of the payment, payment streams that the utility indicates needs to be covered by the security deposit. But the way I, I've seen it and the way it sort of, sort of worked out is the, the opportunity to pay daily delay liquidated damage is out there in the event that the, that the project is not going to achieve commercial operation by the commercial operation date.

But I think it's, it's certainly understandable to have some sort of security in place, or, or the up front payments of these daily delay liquidated damages. But, but having to put that up, you know, at the early start of the project, or having to cover that sort of risk at the early stage of the project really isn't, isn't warranted, in my opinion.

As I mentioned, just the RPS penalties in this for the development deposit. This is, you know, one of the risks that the utilities have identified. Basically, you know, under CPUC decisions it's five cents per kW, kWh, it's capped at 25 million. As I mentioned, there's this good faith efforts exception, but, you know, it is a big standard and it is something that the CPUC perhaps could provide some sort of guidance on, as well.

During the commercial operation stage, you know, I've negotiated power purchase agreements with a number of utilities around the U.S., and here in California the performance assurance is around the highest that, that I've seen charged by any of the other utilities.

And I think you need to look at the, the mitigants that, the risk mitigants that are out there. You know, the primary mitigant being the lender backstop, but then again, you have, you know, major equipment warranties in place, insurance, and you also have the IOU load reserve requirements that, you know, are, that are in place, as well, established by the PUC.

Again, proposed alternative security structures for the commercial operation stage would be step-in rights, subordinated security interest, and requirement that insurance proceeds be re-invested or a buy-down of contract capacity. This, this would be in a, a situation not a termination payment, but in a, where the developer is, is looking to cure a, a delivery default. And again, an assignment of the percent of the buy-down under a turbine warranty. Primarily we're seeing this on the, on the wind side again, and the assignment of a percentage of the proceeds from the availability guarantee.

Under the turbine warranties it's, particularly with the wind, there's going to be availability guarantee, you know, generally in the 95 percent range for wind turbines. And then there's also going to be a, a separate warranty in the turbine agreement for a, you know, buy-down in the event that the capacity is less than what is guaranteed under the, under the contract.

With step-in rights, you know, whether or not these are, or the value of the step-in rights are really dependent upon the lender and what the lender is going to agree to. The step-in rights are going to be subordinate to the senior lender. The, the lender s also going to be concerned, you know, unless the buyer assumes all of the seller's obligations so the lender's under, but the loan agreement and all other project documents, as well.

On the buyer's side, you know, you're opening up potential direct liability by the, by the buyer stepping in and taking over the project and operating the project. There also may be concerns about, you know, the buyer's creditworthiness and whether or not they have the capability to step in and, and operate the project.

It's a time consuming and expensive process, you know, and all the power purchase agreements I've, I've been involved with, and, you know, a number of them do have the step-in right, but I'm not aware of any, you know, buyer stepping in and actually exercising this right.

Another potential option is a, you know, supported security interest in assignments of the warranty payment. And I think these two need to sort of work in tandem during the early period of the operation period. You're, you're covering the exposure to liability risk, you know, by assigning a percentage of the warranty payments. You know, later on the subordinated security interest is going to, you know, have more, more value.

I was, you know, I was looking at, at, you know, Pablo up from this meeting, and I think that, you know, that there is things that could be done by the, by the Public Utility Commission. I think that there could be clarification, you know, on particularly with respect to RPS penalties and, and the utilities' good faith compliance.

You know, I noticed the report, I read through the Black and Veatch report and I thought it was very good for what it covered, but I think the conclusions could, could go, be a little bit stronger, based on, you know, what's being discussed today at the workshop. And we can perhaps develop a, a plan for going forward and looking at and evaluating, you know, what the risks are, what the mitigants are, and whether there's other mechanisms other than just a straight, straight security requirement.

PANEL 2 MODERATOR ACKERMAN: That's it?

MR. McSPADDEN: That's it.

PANEL 2 MODERATOR ACKERMAN: All right. So, commenters, write your questions down, make notes, what have you, and I'll introduce the second part of our presentation duet here, Partho Ghosh.

Mr. Ghosh leads the financial risk products weather and energy specialty products --

man, that's a long title -- WESP Group, within Marsh and McClennan Securities, and Marsh's alternative risk solutions practice. He's held positions at Enron Corporation, Donaldson, Lufkin and Jenrette, Credit Suisse Financial Products, and Salomon Brothers.

So please put your hands together and welcome Partho.

(Applause.)

MR. GHOSH: By way of clarification, I would just like to say that I did not work for the Western Power Trading Desk of Enron. I have a grandmother who likes to visit California, and I would not turn the lights off on her. Furthermore, the very fact that I have to work for living shows you that I am one of the good guys.

Our group structures and places risk with capacity providers, whether they be hedge funds, commercial banks, reinsurance companies, insurance companies. We don't take the risk ourselves. We just structure and place. There are many disadvantages to that, but one of the advantages, we'd like to say, is that we bring, hopefully, at least some of the time, the best ideas and the best products. We're not dependent upon a balance sheet. We're not dependent upon a particular product or technology.

As we discuss risk with CFOs and traders in energy trading companies, the first issue is volatility. The power market, as most of the distinguished people in this room probably know, is different from other markets in that you can't store power, so the volatility is higher. And that's what creates very large collateral requirements.

This graph up here is a not so atypical day in the NEPOOL-Mass Hub. It's in the winter instead of the summer, which is, you know, as you know, the summer is when most peaking occurs. And what it shows is during this day on the X axis are the hours of the day, zero to 24. On the Y axis is dollars for megawatt hour. What it shows is that the power during the day went from $75 to $900 per megawatt hour. Now, that's an increase of approximately 1200 percent.

Now, compare that to the Dow or the S&P 500. A recession is defined -- or, correction, a bear market is defined as a 20 percent decline in index. If you were to have a 1200 percent increase or decrease in Dow or the S&P 500, what would happen? And that is really the issue that we like to deal with when we talk to CFOs, the very issue of if you have volatility somebody has to pay for it. It's kid of like a Newtonian law of physics. You can't destroy volatility. You can't eliminate it. You can only transfer it to somebody. Just like in energy, you can't destroy energy, you just move it around.

And so what we like to think we do for a living is we, we're in the Kurtosis business. That is to say, we like to create pointy graphs instead of flat graphs. Now, what's the point of that? The point of that is that flat graphs have dispersion, and dispersion is another name for volatility. And what we like to do in our business is create a risk management product that reduces dispersion and centers it around the mean.

So if you look at the green line, the variance is a lot less than the red line. That's an actual product that we have that I'll discuss in a second, called power price protection, which is really a contingent call option on power. And that is a real transaction in which the red line is the "before" shot of risk, and the green line is the "after" shot, after we apply our PPP.

Now, using that PPP analogy for a second, because it's one of our hotter selling products, I have a lot of treasurers who tell me yeah, well, I don't need it. So I say to them well, why is that. Oh, well, you know, outage risk, I, I manage it myself. I said, really. How do you manage it yourself? Oh, well, you know, I mean, I decided after much quantitative analysis to do nothing. And I said, really. How much does it cost to do nothing? And at that point we usually get a CFO involved. He said well, I don't know, but I, I just do nothing. Trust me, black box, buy low, sell high. It's very complicated.

And I said well, let's just think about this for a second. First Energy, around 1997, had a 72 hour outage that cost them $120 million in replacement cost. So let's just use that as a base. So if you're saying you do nothing, what you're really saying is that assuming you have the same exposure as First Energy, you're taking out a $120 million line of credit and you're not using it. A $120 million line of credit costs you 75 basis points just to keep it open, and the very fact that you don't use it means there's an opportunity cost of the $120 million.

Now, let's just assume that that opportunity cost is your WACC, your weighted average cost of capital, because that really is your break-even above which you should invest capital. The average energy company in America has a WACC around 12 percent. So what you're really telling me is that you pay 12.75 percent of the limit of $120 million to do nothing. Is that right? And he was like, yeah, yeah, that's right. That's right, you know, that's the number. We can count.

I said, well, gee whiz, did you know that the last 12 transactions we've executed in power price protection have executed at three, at two to four percent of limit? So you're telling me that instead of adding value you're destroying value for shareholders? Do you understand that the CFO is sitting over here, and his fiduciary duty is to shareholders? In fact, he signs the annual reports every year, as per Sarbanes-Oxley? And at that point the guy is fidgeting around, he's sweating, and he, he needs a glass of water.

But the point we're trying to make in that conversation is that risk costs something. Volatility costs something. And you have to carry that risk on your balance sheet. And so what our strategies are designed around is reducing the cost of carry of your risk. So the question we ask CFOs and COs is, is a Triple A rated insurer better at carrying risk than a Triple B-plus energy company. In other words, if you have to carry risk, is it more efficient to carry risk in a good balance sheet or a bad balance sheet.

So the upper line basically says look, you have collateral requirements, but collateral requirements are expensive. And when you give collateral what you're saying is you, the energy company, the generator, are carrying that risk, that volatility, at a very high cost of capital. And the average, again, the average credit rating of the average energy company in America today is slightly above investment grade.

On the other hand, there's a number of techniques you could deploy to in effect transfer the cost of carry to somebody else with a better balance sheet. And that's really what the so-called black box at the bottom is all about. We use securitization, and we use different kinds of credit support to transfer the cost of carry to institutions that are better able to carry it, and thereby reduce the cost of capital, reduce the cost of carry, which should be transferred to Grandma and ratepayers.

Now, what do we mean by securitization? MMC Securities did a securitization with worker's comp in California, a multi-billion dollar deal. What we found is that in the surety market there was a dislocation, and that if you splice and dice the risk and sell it to hedge funds in different institutions with different preferences, there's basically an arbitrage such that you can fund that risk cheaper using securitization than you can in the surety market. At least that was the case in the last couple of years. So we did this for worker's comp.

And what we're suggesting is that if you take all the major long-term power contracts in California from power generators to power buyers, you put your collateral which you're already spending at the bottom as an equity there, you tranche it up into different layers of probability of default, Triple B, A, single A, et cetera. You sell off the top layers to some mono-line insurers. But that bottom layer is going to be smaller than if you have the status quo. And that's what securitization does for you, it reduces the cost of capital. It doesn't eliminate it. It reduces it.

But you can go further. You can add credit support. I discussed power price protection for you. This is a growing market. We've doubled our business in this product every single year. Power price protection allows a generator to transfer the outage risk to somebody else. So if you, the generator, are selling fixed price power long-term, the outage risk, the replacement cost risk, can be transferred to somebody else. Smart thing to do. Contingent call on power.

Well, guess what. That actually enhances the credit value inside the triangle. Why is that? Because if you're a lender you now know that that particular slice of risk is transferred to a hopefully Double A or better entity, and the generator doesn't have it. Likewise, credit, trade credit insurance. If generators have clients, basically trade receivables, and they buy some trade credit insurance that pays off if their receivables don't pay off, then that gives lenders comfort. And lenders will often reduce the rate of interest to an NPV amount that is actually greater the cost of the premiums. That's why that market exists.

But I was fascinated to hear the discussion this morning about the fact that it's all very nice, but it doesn't really do much, because that's exactly right. More and more our customers are saying that's very nice, but it doesn't do much. And so we've created a product called power default protection, which gets at the physical issue of electron. It basically says we will find counterparties, and we've found them in the physical traded market, who will step in and take over the obligations of the seller, and deliver the power themselves. This is slightly different from what we talked about a few minutes ago. It's not the buyer of the contract stepping in. It's a third party stepping in.

So if you have Party A selling fixed power to Party B, Party A pays a monthly premium to Party C, the third party, and Party C steps in Party A's place and delivers physically the power to Party B.

Now, how, how is that? It's that way because there are players that are in the physical market as well as the OTC and the listed derivatives market. And because they're in the physical market they own physical storage capacity. They own railroads. They own generation assets. They own peakers, they own baseload. So they don't just write you a check. They physically have the means of putting the electrons where they belong. And we believe that when you combine PDP with PPP and trade credit insurance you credit support. The structure is such that that equity collateral layer goes down even further. It goes down even further than securitization.

So in our view, this is a potential solution that requires serious consideration. Power price protection is something that's being done right now. Trade credit insurance is something that's been done for a long time. Power default protection is something that we have markets for, we're ready to execute, and a few deals have been done, but not a lot. And the securitization business is nothing new in itself. However, I think what we bring to the table is we're able to lay off layers to monoline insurers that the traditional investment banks aren't able to do because of the relationships and our history.

So our concluding statement to you is that these line items that I saw, let's discuss insurance, let's discuss credit support. They don't make any sense in today's world, because what is insurance and what is a security. What is credit support and what is an index based product. What is an OTC derivative and what is insurance. Those lines are blurring. This diagram up here has four, five different kinds of products simultaneously. And that convergence is what Marshall McClennan Securities is designed to exploit, the convergence of insurance and capital markets.

Thank you.

PANEL 2 MODERATOR ACKERMAN: Thank you, Partho. That was --

CPUC COMMISSIONER BOHN: Gary, can I ask a question just for a second before we lose track of, of this presentation.

PANEL 2 MODERATOR ACKERMAN: No, we're open for questions. Go ahead.

CPUC COMMISSIONER BOHN: Why wouldn't it be cheaper from a public policy point of view to sell that to the utilities, as opposed to the power generators?

PANEL 2 MODERATOR ACKERMAN: Turn on -- Partho, turn on your mic and please speak into it.

MR. GHOSH: You've got, I mean, we're just taking a situation and a scenario and suggesting to our client. It doesn't mean we're -- oh, sorry. It doesn't mean that it wouldn't apply to anybody else. And that's a good idea. I mean, you certainly could look at that target market.

So far, for whatever reason, maybe because our clients have been in the space that we're talking about, they've asked for this solution, so we've thought more hard about that. But there's no reason it couldn't apply to the other segments you're talking about.

COMMISSIONER GEESMAN: Does it lend itself more to a portfolio of projects than to a single contract?

MR. GHOSH: Correct. There is different forces at work there. One is the diversification aspect reduces risk. And there's a co-variance aspect. Certain, certain assets go up and down simultaneously, and that up and down-ness reduces the overall risk, and that, in turn, correlates into lower capital cost.

PANEL 2 MODERATOR ACKERMAN: Let's go to our commenters. Who would like to start? Pedro, please.

MR. PIZARRO: Sure, thanks. Picking up on the question about alternate uses for the products. One thing to consider would be the sinking up of these kinds of product structures with some of the requirements that load-serving entities have in California. So, for example, today we operate, I don't know if, how close you are to these, but today we operate under resource adequacy requirements that are set by the PUC. Those requirements have really migrated the market away from, a little, reliability issue going here to my left. It's a hydro-spill here.

(Laughter.)

MR. PIZARRO: Those, those requirements are really moving us to a much more physical world, and not just physical in terms of the electrons flowing, but physical in terms of the electrons flowing from specific plants qualified for specific criteria. So not only do you have resource adequacy requirements, you also have local area requirements. You have some of the renewable requirements.

So my only point is, interesting stuff. I'm certainly curious to hear more about it as, as the thinking develops. But there's an intersection here between the product types and the very physically driven requirements that the PUC appropriately has been setting up to ensure that we have not just power, but power from the right locations and the right types of plants with the right sort of qualifications.

We have some early steps with the development of capacity products. Again, this, this is still early. And so I, I just throw that out. It's more of a comment than a question, unless you have some perspectives on that. Because, you know, John's, John's question really keyed that up, and you're really talking about products that I think are based on diversifying risk across a portfolio. We had some products like that, some were financial ones like, you know, LD contracts, which no longer count, or will sunset out. They won't count anymore for resource adequacy. So we need to make sure that we're not undoing what the PUC has been doing over the past couple of years.

PANEL 2 MODERATOR ACKERMAN: Okay. Fong, do you want to weigh in with any questions here for either Kevin or for Partho?

MR. WAN: I, I think we're very interested in a cheaper alternative, and --

PANEL 2 MODERATOR ACKERMAN: What do you see here that strikes you?

MR. WAN: It, it's really the way John turned the question around, that we could be, we could be the buyer of such protection. And, and I'm trying to figure out who these physical players are in California. And because we, I don't know about Pedro and Lad, in general, the rule of thumb is that we serve out of one, one out of every 20 American, so we have a very large load, and I'm trying to figure out where the replacements are.

PANEL 2 MODERATOR ACKERMAN: But you're only talking about replacement for securitizing those contracts which you're entering into with third parties; right?

MR. WAN: Well --

PANEL 2 MODERATOR ACKERMAN: You're not talking about your whole fleet.

MR. WAN: I understand that.

PANEL 2 MODERATOR ACKERMAN: Right. I just wanted to be clear of that.

MR. WAN: PG&E only has about 35 percent or 40 percent of a portfolio coming from their own generation with the DWR contracts dropping off and older units falling off. This is a big, a bigger issue in terms of fulfilling our net open. So I'm just trying to figure out who they are, and is it really a financial contract we're talking about, or is it really, indeed, some power plants that he's talking about.

PANEL 2 MODERATOR ACKERMAN: Well, let's push it over to Partho and see what he has to say.

MR. GHOSH: Well, again, I don't want to oversell myself.

PANEL 2 MODERATOR ACKERMAN: Okay.

MR. GHOSH: The physical aspect of this is very cutting edge, and when we've done it, it's, it's -- I can count the number of deals on my hand, and they're very difficult to do and they're customized. And it depends on the acts of the trader. But if you look at the street today, the financial players are increasingly becoming physical players. So Barclay's Capital, Goldman

Sachs, Morgan Stanley, they're no longer just trading contracts back and forth. They see the value and the optionality in owning physical assets, so they have the ability to move around power, store it, in addition to just trade it.

So most of the transactions are purely financial. If you, if you had to break up my book, 90 percent of them, and probably higher, is a product where my markets write you a check. You take that check, and it's designed to be enough of a check to pay for the replacement power. And then you go buy the physical power in the pool. That's most of my products. But we're increasingly seeing demand for and doing without overselling our capacity to do that, sort of a combined financial physical contract where the customer in effect has a choice. They can have a check, or they could actually have somebody step in and fulfill the commitments.

PANEL 2 MODERATOR ACKERMAN: Okay. Thank you.

Lad, comment, questions?

MR. LORENZ: Yes, a couple of comments. All three of the utilities have customer risk tolerances that have been established by the

Commission. We try to manage that risk within those, you know, within those parameters, and are using a variety of tools to try and manage that, you know, manage that risk. You're bringing up some, some potentially new options or new third parties for us to consider in that mix, and that's, you know, that's interesting. We, you know, we're always looking for cheaper insurance, so to speak, on how to manage that, that customer risk tolerance. So, you know, interesting.

The, the comments that I had for, for Kevin were more of questions.

PANEL 2 MODERATOR ACKERMAN: Go ahead.

MR. LORENZ: You indicated in your presentation that there -- you were comparing the cost of, of credit within California to the, to the cost of credit across other markets in other states. I wasn't clear whether the comparison was renewables to renewables or, you know, baseload generation to baseload generation, and whether those are comparable. It would seem to me that renewables are going to traditionally be higher, and that kind of, you know, that would be expected, to me. So that was, that was a question I had.

The, the options that you had listed are all ones that we have been taking advantage of in the negotiations with regard to these specific contracts that we're putting in place, step-in rights and securitization, and those kinds of things, they're all options that we have, we have considered at one time or another. You're right, they can be expensive and time-consuming to try and implement, and I don't think we've actually had to do it yet, but we've got some of them in place. We'll see what happens.

PANEL 2 MODERATOR ACKERMAN: Kevin.

MR. McSPADDEN: The answer to the first question is, is yes. The, what I was comparing the numbers to were renewable contracts, particularly in the northeast. I've seen a lot of contracts in the northeast, and in some of the surrounding western states, as well. We saw some of those numbers earlier this morning. And --

MR. LORENZ: Then my, my follow-up sort of is that it, to me, it's not surprising that the cost in California may be higher, because we have the most aggressive requirements placed on us by the PUC to reach some goals that have penalties associated with those, and those, those penalties, as I think your presentation recognized, can drive the credit requirements, you know, because we are going to be exposed if we don't get there, and therefore we have to look for the best projects, the most reliable, the ones that are going to deliver, and have to put in place those credit facilities to ensure that that's going to happen so that, you know, our customers and our shareholders are protected.

MR. GHOSH: If I could just comment on something you said about cheaper --

PANEL 2 MODERATOR ACKERMAN: Wait, let me have Kevin, and then I'm going to go to you right away. Kevin, go ahead and respond.

MR. McSPADDEN: Yeah. I was just going to say with -- I'm sorry, I lost my -- just a second. Let's --

PANEL 2 MODERATOR ACKERMAN: Don't tell me you forgot, because we're all in trouble.

MR. LORENZ: It wouldn't surprise me if the costs in California are higher because of the requirements that we have for the 20 percent renewables.

MR. McSPADDEN: And you're talking about the value of the step-in rights and the other things, and I agree that I would prefer looking at the mitigants and trying to determine what the risk actually is out there. I agree that, you know, some of the alternatives, there's, there's some value to it, but, but I think that, you know, trying to evaluate the, the risk and the mitigants would be a more worthwhile exercise than trying to look at some of the alternatives that are out there.

PANEL 2 MODERATOR ACKERMAN: Partho.

MR. GHOSH: Yeah, I just want to pick up on that comment you made about cheaper insurance. I think it's important from a public policy point of view to not get too hung up on labels. I mean, if you let utilities pass on insurance but not OTC derivatives, for example, you're really limiting yourself. What we're finding increasingly is there's an arbitrage-ing going on between the derivative markets and the insurance markets such that often the risk is more efficiently priced and more cheap, in effect, through, for example, hedge funds.

So a concrete example right now is in the Gulf of Mexico. We're working on the structure, we're transforming hedge fund capacity into insurance capacity simply because there's a shortage of insurance capacity. It's a different pool of capital, and we're able to get cheaper pricing for clients because of our ability to transform one into the other. So I think when you talk about cheaper insurance, it's important to let go of the old paradigms and the old buckets and the old labels and really talk about cheaper risk management product.

PANEL 2 MODERATOR ACKERMAN: Very good. I was wondering, Commissioner Bohn, how would you react to Lad's comment that maybe the cost of risk mitigation instead of credit is due to the rules that are imposed upon the utilities by the Commission. Do you have a reaction to that?

CPUC COMMISSIONER BOHN: Can I have an alternate question? No, I --

PANEL 2 MODERATOR ACKERMAN: I don't have an alternate question.

CPUC COMMISSIONER BOHN: No, seriously, it's, you know, it, it's probably right. I think any time you start dealing with regulatory mandates there's a, there's a premium cost that, that sneaks in there, almost no matter what they are. I'm, I'm less concerned about the structure, because to, to Partho's last, last point, scurrying around and finding whatever is the appropriate risk capital is what people do, and sometimes they're in the insurance business and sometimes they're in the investment banking business, and sometimes they're in the lending business. That's all fine. It all comes down to what is the cheapest cost to get this process underway to the ratepayer. And whether the product looks like a, a duck or a goose or a swan is really not very important, as long as it does the job.

I'm, I'm struggling with, with the process as, as we go through these conversations, I'm struggling with the process of with all of these alternatives out there, and if it is in fact the case that the reason for special purpose vehicles is to insulate a particular power plant from the risk of bankruptcy of the parent, it would seem to me that one could deal with -- step-in rights would seem to me to be a much more, just arbitrarily, a much more valuable right, and would mitigate the risk a lot more than it seems to be recognized here. And I'm trying to figure out why that is not kind of a natural thing to do.

PANEL 2 MODERATOR ACKERMAN: Let's hear from Fong.

MR. WAN: That was my conclusion about a year ago. And PG&E has retained several law firms to try to learn what's the best practice out there, and truly get a good solid step-in right. And we tried through our long-term RFO to structure some of those transactions, and we can, we welcome any help you can offer us. We, we couldn't seem to find the right situation where we are really subordinate to the primary lender, and we could find the right structure, in terms of governance, and how to avoid bankruptcy, because during the, during the course of bankruptcy we actually lose our step-in right.

We need to get in there just in the right time. And --

PANEL 2 MODERATOR ACKERMAN: Is that the only time you lose your step-in right, during bankruptcy -- if you're in bankruptcy, the buyer's in bankruptcy?

MR. WAN: No, no.

PANEL 2 MODERATOR ACKERMAN: Are there any other conditions? The seller -- oh, the seller --

MR. WAN: The seller's bankruptcy we lose the step-in right. I can't, we can't move in.

PANEL 2 MODERATOR ACKERMAN: You can't move in. I see what you're saying.

MR. WAN: That's the way I understand it.

PANEL 2 MODERATOR ACKERMAN: Okay.

MR. WAN: And I think, John, we should explore this possibility a little more. There, there doesn't seem to be a best practice out there where someone can really exercise such a vehicle effectively.

CPUC COMMISSIONER BOHN: Are, are the, just generally, for anybody who, who knows the answer. What is the attitude of the debt lenders towards step-in rights? I mean, I can understand either way they would make some sense, or they might be antagonistic. What is the market saying about that?

MR. McSPADDEN: I think, I mean, John, you might have more perspective on that. But generally, the lender wants to step in himself. He's -- already had contingency plans for stepping in in the event of a bankruptcy. So, and to a large extent, the utility would be in the way by stepping in and create additional problems for the lender. So, John, I don't know if you have any --

MR. BUEHLER: We've had some issues with step-in rights around some projects, gas-fired projects in California when, when PG&E was, was bankrupt, and involving things of a range of, of stepping in to take over the plant, which was not a, not a comfortable alternative for lenders who weren't used to doing that kind of thing, which describes virtually all lenders, through trapping cash flow to the operator, and therefore the owners of the project, neither of which were terribly desirable.

But we just ended up running the plant until PG&E sort of corrected itself, which was inevitable, and got the cash flow out of the project about a year and a half into the PG&E bankruptcy and, and went on doing business. So I think the, the threat was, was more compelling than the reality in that circumstance.

PANEL 2 MODERATOR ACKERMAN: Okay. Let me move on. I, I just want to check. Joe, John, and John, do you have any, any of the three of you have any comments or questions to --

MR. TORMEY: Please. I guess I'd throw out, with respect to the bankruptcy risk, if we're talking about a project finance structure, by and large the, the special entities are going to be ring fenced. And so from my perspective, I agree with Fong. It's difficult to structure step-in rights. It is an issue. And subordinated, subordinated liens can sometimes be an issue.

From my perspective, what that gives frequently to the out-taker is it's a place at the table, and they've got some increased rights. In a project finance structure, frequently you're not going to end up with the SPV in bankruptcy. It doesn't do the lenders any good, right? They're, they're stepping in, as, as Kevin pointed out, to take over the project, so they foreclose under the, under a pledge agreement, they foreclose under the security agreement, they foreclose on the first mortgage. They take over. All of the, the rights that the utility had, if they're the off-taker, then give them a place at the table and a, and a better possibility of negotiating some sort of reasonable fix.

But by and large, again, in the project finance world, where we're talking, you know, single projects, SPVs with an off-take, I'm not sure that the bankruptcy risk is, is quite the same concern as some of the other structures that have been out there where some of the larger IPPs were, were not financing in that, that sort of manner.

PANEL 2 MODERATOR ACKERMAN: I'm going to go to you, Lad. I think you wanted to make a comment.

MR. LORENZ: The only comment I, I was going to make is that, that the step-in rights are, are different. For the utility the option to step in is because we have a need, we have customer requirements that we're trying to satisfy. The lender wants to step in to protect, you know, their, their investment. And that, you know, therein lies the conflict sometimes.

The other interesting thing is no bank advised us on our step-in rights, so on one of our contracts we're still trying to sort through. So, you know, it, I mean, it's a, it's a tough issue.

PANEL 2 MODERATOR ACKERMAN: The bottom line, step-in rights are messy and sometimes -- messy.

Okay. Curtis.

MR. KEBLER: I realize I'm not a commenter, but I just had a question about the issue of --

PANEL 2 MODERATOR ACKERMAN: No, that's quite all right. We'll give you 30 seconds.

MR. KEBLER: -- of step-in rights. If, if -- it seems like the step-in rights are project specific, so if it's the utility that's conducting the RFO and it's the utility that's seeking the step-in rights and the step-in rights are project specific, or do you run into issues about -- you don't have standardized step-in rights, or maybe you do, across all these different projects, and if they're not standardized, then you, you sort of, you've, you've negotiated a bilateral arrangement for this project that's not applicable to all the projects participating in the RFO, and now you've got issues there in terms of your ability to evaluate and select winning projects.

Just a question, if that is an issue.

PANEL 2 MODERATOR ACKERMAN: Who were you directing that to?

MR. KEBLER: I was directing that to Fong, or, or perhaps Pedro, if they thought that was an issue.

MR. WAN: Well, I think we never got that far. I want to be clear. We, we probably spent a good million dollars getting good legal assistance, but I couldn't figure out how to make sure this is clean and could be done in a timely fashion without holding up our RFO. I just couldn't figure out what, what is it we were getting, and we weren't even able to compare across the offers. I think that was your point.

MR. PIZARRO: Maybe, maybe I can just add the second that we have taken a look at step-in rights in the context of specific bids. You know, we had to discontinue new Gen-R for the last year. But there was some discussion with particular projects there. We had -- it's come up with some of the renewables, and we're pretty much in the same place as Fong, where it's been difficult to -- I see Bobby Little over here is shaking his head here -- it's been very difficult to get to the end game with these.

The other piece of step-in rights I just wanted to share, highlight, was in one of the, it may have been Kevin's charts. Let's not forget that although it's a right, it's also giving the buyer direct line of sight into a potential liability. So if you're stepping in you need to understand what all you're stepping into, or you may be stepping in it.

PANEL 2 MODERATOR ACKERMAN: You have a one-word suggestion in mind?

All right. We've got to move on. Time is -- a very good conversation, I thought.

I'd like to introduce now John Buehler, Managing Partner at Energy Investors Fund, and previously he served as the Chief Business Development Officer as well as General Counsel of his company. And prior to that, he was Associate Counsel at John Hancock, and practiced with the law firm of Bingham McCutchen.

So please put your hands together and welcome John Buehler.

(Applause.)

MR. BUEHLER: Thanks, Gary. A pleasure to be here.

We were charged with, with trying to think outside the box, and as I will introduce myself as a private equity guy, it's very hard to figure out exactly where the box is and what's inside it and what's outside it. And I hope that we can at least leave this discussion with some confusion about some of those issues which may lead to some, some appropriate discussion.

What's all that mean? Well, just to ratchet up to the level of private equity funds, there are now about -- in 1987, when we started energy investors funds, there were, there was one. There are now about 700, and probably 500 of those are, are hedge funds. So there are a lot of participants on the side of supplying equity to developers who are developing projects in conjunction with off-take arrangements to utilities, and a tremendous amount of, tremendous volume of capital has been raised in this sector over the last five years, where we went from maybe 50 funds to, you know, 700. So a lot of activity.

The typical investment scope is power and energy assets, and companies, the end company's part kind of incented by EPACT, a lot of, a lot of discussion about whether or not EPACT will clear the way for more utility mergers and acquisitions, et cetera, et cetera. The typical funds invest in either technology or, more specifically, power and energy assets of the type that you've been talking about, generation and transmission specific.

Asset and corporate plays are -- all involve non-recourse project financing and some M&A, and I'm going to focus on the non-recourse project financing, because that's what we do, and I, I know that's been a part of the discussion this morning, which, which I, I missed.

The focus for the funds is, is credit analysis. This is kind of in conjunction with that the banks do. So you borrow some money and you bring in some equity because that reduces the pay-out when you have finished constructing the project. It kind of targets the returns for a project's equity 15 to 25 percent, something like that. Obviously it's been scaling down with time.

That's a pre-tax measure, so it effectively reflects the, kind of the return on equity that's permitted to the utilities on an after tax basis. That's kind of the rough predicate for that number.

Some facts and assumptions that private equity funds would make as they look at the universe and try to figure out what's inside the box and what's outside the box, and this will all lead to just a brief introduction to some new project types that we're looking at and other people are trying to develop now, including coal to liquid projects and ethanol projects, et cetera, bio-fuels and, and then just a little skip through the, through the wind business.

But in any event, the motivators for us are that oil consumption has increased by five times over a projected 18-year period, or will, will increase. We have to do something about oil dependency. These are kind of top down dictates coming from the various levels of government. Domestic refining capacity is flat. We all know what happened with regard to Katrina. The generating capacity in the United States post-World War 2 is old, has to be retired, a lot of it. Coal and nuclear through the decade of the nineties, and then almost all natural gas. And we all know what happened with natural gas prices.

LNG, well, 44 or so proposed terminals. Who knows how many will build. Some people are bearish about the opportunities for LNG internally, but on a international basis I think the commodity issue and competition are, are compelling.

And then we'll look just briefly at EPAct and renewable portfolio standards and see what we've come up with in all of this mix.

The California summer of 2006, not specifically about California but capacity margins, generally speaking, in the United States, have shrunk since 2003, and the exception '05-'06 is the southeast and the northeast. Transmission line mileage has increased, and we've seen the introduction of some new point of service transmission systems like the Path 15 system here in the Central Valley in California. But the growth rate of the transmission line mileage is trailing the growth in demand and capacity, so we're headed for some more generation crises, and perhaps transmission crises, and then you can see kind of the summer peak numbers and we always get excited about this as we head into the summer, and you travel to Sacramento and it's 97 or so.

The conundrums that all this produces, and I just picked a couple of conundrums, I'm pleased that I was able to spell it correctly, I hope. What do all these market conditions mean for what projects are being developed, what projects utilities are seeking to have developed in conjunction with some kind of fuzzy mandates that we have at the, at the national level, and perhaps less fuzzy mandates at the, at the state level.

We'll take a look at just some coal-to-liquids, ethanol, and biomass opportunities, and those are as new to me as they are to everybody else. Ethanol has been around for a while, but to scale it up to the scales that we're talking about involves a lot of business and a lot of capital and a lot of judgments people have to make with not that much information. It's not gas-fired and it's not coal-fired. It's different, and the technology is different, and that presents some, some challenges.

We have, by virtue of renewable portfolio standards, Kyoto and other things, including common sense, decided to spend a little bit more time, effort and capital on the renewable side of the business here, tie in transmission, because obviously the best wind regimes aren't necessarily in downtown San Francisco, where there is access to, to transmission. Transmission has to be built, but nevertheless, we ought to take advantage of those kind of God-givens.

And what will it take for equity money to fuel those kind of projects, to back the fuel projects and the renewable energy capacity projects. Renewable energy, we're, are doing and have always been doing. I think we started out owning about a thousand wind turbines in the Altamont Pass back in 1990 or '91. And on my second visit after the first visit to see the, the network for putting together the, the turbines, the first of the turbines failed, had a part failure, and within 48 hours all thousand of the turbines we so proudly owned enjoyed the same part failure. And we're beyond that regime, fortunately, so this has become a fairly, a fairly static way of, of investing.

I mentioned EPAct and its incentives to get around the, the oil dependency. Suffice it to say that there are incentives to do things like ethanol production, bio-diesel projects and coal to liquid projects. And therefore, because there are incentives, debt forgivenesses, et cetera, there are developers doing it, not just because of the incentives. It, it will fulfill the, the larger purpose that we have. But in any event, there are more project opportunities out there than we've seen in, in many of these categories. Not many getting done in many of these categories, but we'll talk about some of the risk profiles of those.

Federal and state incentives are absolutely necessary to get people involved with this, both with regard to some DOE and state level DOE kind of, of grand moneys. Those bona fide the project, and they added to the, the PPA issuing state will have about getting those projects built in, in its jurisdiction. And I think that's important to people when you're looking at assessing risk and developing those kinds of projects.

And in the coal-to-liquid projects we're seeing kind of massive scale projects now being introduced, or at least announced. Tremendous lead time, typical of the, of a typical coal project. And the general, the general theory behind it is these projects become feasible when oil prices are high enough so that the cost coal and the conversion costs effectively make it economic. And we're all trying to figure out what exactly that means.

And now financing issues for, for fuel projects, and I'll, I'll just raise some of the highlights. We'll take out the volatilities here.

Generally speaking, there are two kinds of equity, the kind of equity that took the merchant, merchant power risk over the last five years of the decade of, of the nineties, and those who didn't, those who were looking for a power purchase agreement regime with more modulated returns and more modulated risks.

This whole project finance business is an allocation of risks, so let's just look at some of the risks that we'll all be analyzing for purposes of providing financing for these kinds of new fuel projects.

Futures contracts, and you kind of put a collar around the price volatility of all of the moving parts, diesel, ethanol, coal, corn, soybean, who owns it. Should I, if I'm developing one of these projects buy the raw resources that I need to convert into electricity, et cetera.

Are there long-term contracts that are available, can they be executed at fixed plus escalator pricing. That's key not only to the utilities who are going to be involved, but also to get the capital out into the sector to get these things developed.

Fixed, fixed price turnkey EPC

contracts. That's the, the gist of, of our, our contracting and the gist of the stability in, in building a new plant, be it a coal-to-liquid plant or a wind farm or, or a gas plant, is the, the creditworthiness of the EPC contractor and, obviously, the creditworthiness of the off-taker. In a new regime of EPC contracts you're going to see some, some different terms and conditions. We've had a little bit of a discussion about that around Kevin's, around Kevin's presentation, but all of these things, all of these elements of traditional analysis are going to be new, newly embarked upon.

And some of the risks will be allocated to parties that we're not used to allocating the risk to. For example, the bottom bullet, recourse to the developer equity investor. Well, that's anathetical to the nature of project financing, which is non-recourse to assets of the developer and equity in excess of their capital commitment to the project, but that's all called into play by this, by this new regime.

And here are some more guarantees, warranties, et cetera. We have delivery system issues with ethanol plants, and gas station issues, et cetera, but those will have to be encountered, and I'll show you in a kind of a ticker presentation, the last couple of pages, some of the, some of the responses to this.

The bottom line is, I think, with equity now having 700 funds' worth of dollars for this marketplace with there being technology oriented funds, as well as kind of the old standby non-recourse project financing funds, we will have an interest in CTL and ethanol and biodiesel projects to the extent it's backstopped by the government mandates as it flows down through the state level to the PUCs and the, and the utilities.

Taking a look briefly at, at energy projects on the renewable side here, read wind principally. The key to all of this effort has always been monetizing the tax subsidies. The businesses basically haven't worked without tax subsidies, so monetizing them is critical. You, generally speaking, have a couple of kinds of equity.

You have tax sensitive equity that can utilize and monetize the tax subsidies based on structural fixes, and they're relatively simple. And then you have non-tax equity that finds it difficult to -- and, and that's kind of pre-tax measured equity like, like ours is -- which finds it difficult to participate in renewable energy projects just because of the difficulty in converting and monetizing the tax subsidies.

And this is a typical structure of the partnership flip structure, where you basically allocate cash flow and tax on a disproportionate basis until the tax equity has received an internal rate of return. These kinds of structures will still be in place, and in place, in fact, with regard to biomass and other structures that can utilize sale lease-back structures, as well. So rather than belabor the technique of all of this, it's, suffice it to say that drivers including tax incentives are still critical and will be analyzed by the appropriate debt and equity marketplaces.

Financing for wind, I'd only stop at the technology side here. There has been, because we have had so many announcements, through renewable portfolio standards and otherwise, of the need for increases in wind development, and we have untapped wind regimes in the United States. We've had a, a broad discussion about technology and new entrants to the technology field, including groups like, like Clipper, which was an old Zons entity, then an Enron entity, and finally a GE entity, entering the marketplace with more competitive turbines, competitive in the sense that they're more competitive with the European turbines that had dominated the markets even in the United States through the nineties.

So wind will continue on the same basic analysis as before, and I'll show you some remarkable interesting trends that have happened. It's kind of the ticker, and these I just pulled off of, off of the ticker literally last night to add in.

Some remarkable things which I think bear being -- bear being talked about. The California PUC decision of a couple of weeks ago to allow utilities to basically charge the ratepayers today for transmission costs that you will incur in developing renewable energy projects. A tremendous incentive for wind developers who are used to capitalizing that cost in the project development part of the process. So if you want to incent wind development and project financing around wind development, that's a good start.

On the development of wind, wind projects, just to give you some sense of pricing, there was a big syndication that took place fairly recently for Horizon Wind Energy around two projects, and this is just a brief display of the kinds of tenor and terms, 15-year debted, a -- wire spread that steps up over time, but pretty decent financing. So effectively there is capital for well, well-developed projects with transmission access, with, with the PPAs.

Renewable energy IPOs. We have had a, there's, there's a format now for financing on the ethanol side where effectively you don't really need a product, you just need a vision. And Verison took that vision and was successful in, in an IPO. You can see kind of the launch price and then the opening price. I believe that the prices kind of operate around the pricing for these kinds of IPOs in the, in the ethanol sector kind of operate around the price per gallon for, for the product when, when it is built.

But this just shows you that, that, you know, there is the beginning of an irrational market for a rational result here, and we'll end up seeing what Verison does with its, with its IPO stakes, and obviously in converting into bricks and mortar. So an IPO without bricks and mortar on the basis of a concept, and a concept that has been proved in smaller scale but now we're ratcheting up.

And then finally, NRG Utility utility affiliate announcing intentions to build three coal gasification projects, Delaware, New York and Connecticut, and seeking long-term PPAs to do that, NRG as a result of this has received a lot of phone calls from private equity asking if there will be some equity opportunities to do something like this.

So in conjunction with new ideas consistent with the download we've had from EPAct at the state level with the vision of, of Commissioners, Energy Commissions, PUCs and utilities, people are still looking to be on the cutting edge of, of new technologies and new ways addressing -- of addressing energy shortages. And I look forward to follow-up questions. Thanks.

PANEL 2 MODERATOR ACKERMAN: Very good. Let me introduce our next speaker here. Let me get his slides up, and then we'll be able to go here.

Russell Read is the newly appointed Chief Investment Officer of CalPERS, the world's largest pension fund. He's responsible for the strategic plan, including tactical asset allocation, risk management, business development, budget authority, it goes on and on. His previous professional assignments include stints at Deutsche Bank and Scudder Investments. His academic achievements are extensive both at the University of Chicago, my alma mater, and Stanford University.

Please put your hands together and welcome Russell Read, of CalPERS.

(Applause.)

MR. READ: Hello, everybody. Thanks for having me here. Let me go over a little bit of what we're looking at at CalPERS. We're, we're an important source of capital. I think we're leaders, sort of, in terms of channeling capital toward, toward a number of the projects that, that have been discussed here today, so let me go over a few of them.

One is that energy and materials represent an increasingly important opportunity for us in the capital markets, and I want to provide a little context for you. You know, in 1980, energy and material stocks represented one-third of the capitalization of the S&P 500. I was a young high school student in the 1970s, in Houston, Texas, and at that time, you know, you knew a few things, that, you know, one, energy companies were growth companies at the time. They were in the high PE ratio companies. Six of the top ten capitalization companies in the U.S. were energy companies.

That changed pretty dramatically in the capital markets, you know. Basically from 1980 until the year 2002, roughly, you know, there was a, there was a protracted diminution in terms of the importance of energy and material companies in not only the U.S. capital markets but worldwide. By 2000, in particular, energy and materials accounted for 7.8 percent of the S&P 500, so it dropped from one-third of the importance in the capital markets to under eight percent. And despite the run-up we've had, you know, in, in the capitalizations and the number of companies, including Exxon and Mobil, for instance, these sectors only account for about 12 and a half percent of the, of the capitalization in the S&P 500.

The, some of the keys that we're looking for is really a recapitalization of the sector. We're anticipating that in the, in the capital market sectors, for instance in the S&P 500, we expect that, that the importance of these sectors are, are going to grow to in excess of 20 percent. Basically, you know, as you know here, a lot of capital will be needed to finance these projects. We don't, you know, in terms of like the amount of liquid fuel that's, that's going to be needed worldwide, we're producing 86 million barrels a day in, in petroleum, you know.

What, what is that number going to increase to? It's certainly going to be a pretty, a fairly big number, you know. Is it going to be 110 million barrels a day or 130 million barrels a day, how much of that is going to be picked up by -- will need to be picked up by alternatives. You know, there's probably a good chance that, you know, we're not going to be able to do that with petroleum alone.

This is a, this is a significant area for us, and one in which from a capital market standpoint, we're, we're allocating a great deal of capital because, frankly, this is where we're seeing a great deal of opportunity, particularly in the renewables market.

Let me describe the areas that we're investing in. These areas are likely to grow pretty considerably. This, these numbers represent several billion dollars in, in each of the categories that we'll be talking about.

The four, the four organizational areas that, that we look at at CalPERS regarding energy and renewables in general, include private equity, public equity, real estate and fixed income. I'll go into a couple of these in some detail to give you an idea of what they are.

In private equity we have a clean tech program. I'll go into some detail with that. It's $200 million allocated so far. That number is likely to increase very dramatically over the coming years. Public equity, you know, developers of renewable energy technologies, new IPOs, we, we're, of course, important participants with the public equity markets. Real estate, our green wave initiative, we're important real estate developers not only in California, but worldwide.

And our green wave initiative, for instance, has certain mandates. For instance, a reduction of net energy requirements in all of our buildings on an aggregate basis, and more than 20 percent over the next five years. Water requirements, waste requirements, certain stipulations about how we are going to be building our projects. So the way we're doing real estate is going to be fundamentally different based upon energy needs, water needs, and waste needs.

And fixed income. Fixed income, we provide, of course, debt financing of four companies in, in both renewable and non-renewable energy and material technologies. We also provide credit enhancement for qualified municipal utility projects. One thing that's missing here, and it's missing for a reason, we, we generally do not have private placements for fixed income projects. Okay. So there's not an energy group that works with municipalities on a private placement basis. It's a possibility in the future. There are organizational reasons why, why we don't have that, that private placement capability. Generally, you know, the ability to, to work out covenants and, and other things would require some significant organizational changes.

So the key here is that these are the, these are the areas right now which we participate -- in which we participate in projects that are relevant to this conference.

Let me go over a couple of them. One is in the CalPERS fixed income program, a credit enhancement program. In the year 2003 we started a program. It was a $5 billion program dedicated to credit enhancement. So think of -- other organizations that provide credit enhancement, we also provide credit enhancement. We're particularly interested in providing credit enhancement for, for bonds where our Triple A rating can be helpful. Again, we're only $550 million into this program. Lots of capacity. I have a contact, just in case you're interested. Of the 550 million, 150 million has been deployed in the, in the energy and in the, and in the material sectors, specifically in some water resources power supply revenue bonds are part of the book, totaling $150 million.

So again, lots of capacity in, in our credit enhancement program.

Now, the, in contrast to the fixed

income program, notice with, with fixed income for the credit enhancement, the idea was you call CalPERS. Right. You give -- well, you don't give me a call, but you give somebody at CalPERS a call, and we provide the credit enhancement. For most of our other investments we have, we actually, you know, we work with, we work with, with other firms. We have partners such as, you know, our previous speaker, John -- right, Greg. Okay. Sorry. No, John, that would be a good example of a partner. And we allocate lots of capital through our investment partners.

Let me give you an idea of, of what we're, what we've done in the Clean Tech Program as an example. Again, this is a program, this program itself will be likely to be, it's likely to be supplemented. We'll have other similar programs. The, the CalPERS Clean Tech Program approved $200 million for equity, for private equity investments that were oriented toward our primary objective. We are a pension plan. Our primary objective is achieving strong long-term risk adjusted returns. And the secondary objective is capitalizing and clean technologies that can provide, you know, that can provide for job creation and, you know, and simply better renewable, better renewable energy alternatives.

So to date, all $200 million has been committed. We'll be looking at increasing this amount.

Who are our key partners in this. The key partners are, one, we have an anchor advisor, Pacific Corporate Group, and secondly, we have a separate advisor, Environmental Capital Group. So these are two, these are two firms that you would contact if you were looking for venture capital, venture capital money. These are your venture capital firms. You would, you would call these two partners, and you would work with them to, to obtain venture capital financing.

What do we invest in. It's really a broad range of Clean Tech initiatives. You know, it's energy, it's fuels, it's -- the full range of fuels. The, it includes certainly water, it includes waste. So it, it's meant to be a fairly broadly construed idea, what Clean Tech is. But generally, you know, more efficient, less polluting means of providing energy and materials.

Okay. Market drivers. What are we looking for here. We are looking at strong returns. You know, if you went back, you know, five to ten years ago, this would not have been a sector that we would've allocated such, such attention to and such capital to. Frankly, having, you know, having attractive, having, having high energy prices, for instance, energy prices that we can lock in effectively for now it's with the, with the petroleum markets, with, with gasoline, with natural gas, we can go out six and a half years and basically lock in favorable, favorable sale prices for energy commodities that make a lot of private equity investments attractive.

So high and volatile prices are, are, have really changed the landscape for us. It's made it, it's made this an increasingly attractive, a pure investment sector, and this dovetails with, of course, our secondary objectives with, in terms of, you know, providing better alternatives, environmental concerns, and, of course, government awareness for this.

What is our aim? We're looking for diversification. This is an important area. We will be investing directly in the commodity markets for the first time, likely at the end of the year. But natural resources investing is a, sort of a newly reborn area for us. It's both energy and materials. It's an important source of diversification. Prudence, you know, we are looking at a patient investment approach. What you've seen is, is something that amounts to several billion dollars.

But frankly, you know, over the period of the next ten years, we'll be looking at, you know, several billion dollars invested in new capital on an annual basis, you know, so this is a, this is an important protracted effort for CalPERS. It's something which is not going away. The, the several billion that we have invested now is not, is not the end of what we're seeing. This is an institutional investment process. It's part of our overall asset allocation, and it's one in which, you know, our return expectations in this asset class are increasingly, are increasingly attractive to us.

So with that, I just want to show you one final thing on our, on our venture capital. Here are, here are seven venture capital funds and how we've -- it gives an example of how we've actually participated with them. So these are, these are venture capital funds in which our partners have selected, this is where the, for instance, the $200 million in Clean Tech, Clean Tech dollars have been allocated at all stages of the venture capital and private equity process.

So with that, I'd like to turn it back to Gary.

PANEL 2 MODERATOR ACKERMAN: Joe, what's your pleasure here, Joe Desmond. Do you want to take comments and questions?

UNDERSECRETARY DESMOND: I'd like the Q and A, take a short ten-minute break, and then come back with the last two.

PANEL 2 MODERATOR ACKERMAN: Okay. So, let's see. Previously, I started with Pedro. Let's start with John Tormey. Do you want to offer up questions or comments for either John or Russell?

MR. TORMEY: No.

PANEL 2 MODERATOR ACKERMAN: Okay. I'm tempted to ask him again, but I won't.

MR. GRECO: Yeah, I'll take a shot. I, I guess, from both presentations for John and Russell, we talked about long-term risk adjusted financing. The balance, or, or I should say the,

the discussions earlier all revolved around collateral issues, credit requirements, and the difference between a, a mark-to-market replacement value versus some sort of fixed or capped risk.

How is a, as investors, would you view the criticality of the difference between a mark-to-market replacement value versus some sort of capped risk within replacement power.

PANEL 2 MODERATOR ACKERMAN: Start with John, then go to Russell. Is that okay? John.

MR. BUEHLER: Sure. I missed the earlier discussion, but our, our own particular view about asset acquisitions, and you can kind of fit this into your, into your question and if it isn't responsive, just let me know since you're right next to me here. Yeah, you can just, just give me a nudge.

We have taken a fairly cautionary approach to investing in power assets, which means we have tried as much as possible to limit risk whenever we could, either by not encountering fuel risk, seeking pass-throughs under contracts and, and principally recognizing that our partners in the deals that we do are the utilities. We have a customer, and we have a customer relationship, so we have tried to work through the power purchase agreement regime almost exclusively.

The, the one exception to that rule in the hundred assets that we've acquired over, over 20 years was a, a pure merchant deal in Massachusetts next to a contracted for deal in Massachusetts where we did both at the same time. And we got creamed on the merchant deal and, and we made a ton of money on the contracted for deal.

So effectively, our approach consistent with the approach that our investors want us to have, and our, our traditional investment philosophy is not to encounter market risk to the extent we can avoid it, and to do something about it to the extent we can do something about it effectively. And that may not answer your question, but go ahead and nudge me if it doesn't.

MR. READ: No, I think that was helpful.

PANEL 2 MODERATOR ACKERMAN; Okay. Russell. I'll go to you, Fong, after I get Russell's answer.

MR. READ: Yeah. The, the risk question, the risk mitigation question is an interesting one. In some ways, we're, you know, at the CalPERS level, we're relying on some risk mitigation being done at the venture capital level, you know, so it's with -- in our Johns level. Then at, at the, at the CalPERS level it's a little different.

One is that there's, there's natural diversification that we're getting across the natural resources sector. There are a few projects, you know, there are, there are some projects that, that will actually put on conceptually an overlay, a risk overlay ourselves. You know, for instance, if there's a project which looks generally promising but, but something which would be, something that would make sense, let's say, if, if crude oil is over $40 a barrel, you know, will we, will we, you know, enter the, you know, will we, will we short, you know, the energy futures markets over the, over the next six and a half years, starting today, to sort of lock in, you know, an expected profit margin.

So, so at our level, it's, you know, it's reliance on risk management techniques to be conducted at the venture capital level or by the, you know, by our partners, and at the, at the higher level we'll, we'll do risk management based upon our expected exposures to, to changes in, you know, in some of the commodity prices.

MR. GRECO: And that's an overall cost of that for the, the limited, for each limited project.

MR. READ: Yes.

MR. GRECO: It adds up. It adds cost.

MR. BUEHLER: One more thing I, I might add, Joe. We also approached the portfolio theory kind of on an asset by asset basis, so rather than acquiring portfolios of assets that are being sold where there may or may not be similarity between assets, we diversified by making an informed judgment for our asset play number four, based on what we did with the first three judgments effectively. So at the end of the day we have a portfolio of 15 to 20 project investments which are selected individually, by and large.

PANEL 2 MODERATOR ACKERMAN: Fong.

MR. WAN: John, I, I think EIF just bought in on two of our projects; right?

MR. BUEHLER: Yes.

MR. WAN: And I think the question that you asked earlier, Joe, right, was what you think of the credit requirements in a project you just bought into.

MR. BUEHLER: We were obviously having, having bought into them, they -- we were pleased. I, I think the process, for, for the edification of people who are probably in the dark about this, we've been working for a while with, obviously, with developers because those are the people we provide funding to. In this particular circumstance, a major utility's affiliate, a development affiliate had been developing gas-fired projects in, in California and bid into a PG&E request. And in, throughout the process, the identity of the development group was somewhat in play because they were about to be acquired, or were in the process of being acquired by another utility and weren't really certain what their own future was going to be.

In any event, we solidified the situation with them. The development group were awarded two, and I think three all together, contracts in the PG&E process. And it was remarkable for us because it was, they were actually awarded to us as, in effect, in the name of a private equity fund with a, with a developer partner, based on the experience that we had both in asset buy and holds here in California, and with one of the first of the, of the major gas-fired deals, the Crockett Project, which we had owned and, and helped operate and now own a greater percentage of, almost all of the project.

In any event, we were able to negotiate very directly with the contract people at PG&E and it was an open and transparent process, and I think that helped both of us explain what our bid and offers were and what our wants were, and we found it to be a, a rewarding public process, effectively, as opposed to a private process, and, and I think it was handled that way.

So we had a law firm alongside us looking at the particular requirements and didn't find them onerous at the end of the day.

PANEL 2 MODERATOR ACKERMAN: Did you get the answer you were looking for, Fong?

MR. SALTMARSH: Gary, I think he did.

MR. BUEHLER: Can I interject just one, one quick second here. One of the issues that keeps coming up is this risk about the volatility of natural gas prices and everything else. It would seem to me that you could hedge that risk equally on behalf either of an independent power producer or a utility. Are there any differences in, in the analytic process? I mean, there are obviously different credit requirements, but one, it seems to me you could choose to hedge it at the power producer level or you could choose to hedge it at the utility level. Are there any differences?

MR. BUEHLER: This would be a good question for, for our PG&E friends to answer, as well. But it, if you look at the, at the kind of the etymology of, of project finance where it is non-recourse, that would involve, obviously, an element of almost recourse that it has historically simply not been involved. That's not an answer to your question, but it's just, it's just kind of the position.

The, the history of, of power project financing has found the utilities, generally speaking, announcing the kinds of fuel choices they wanted to be bid into their request for proposals, and also typically the, the cost and fluctuation of fuel has been passed through with an energy payment, effectively, so that the, the project is empowered to, to buy fuel. Sometimes it buys it directly, or tolls it through the, the utility that it has the off-take arrangement with, and it, it just has been the convention.

Could you convert that and say it's going to be the developers, not -- and not the utilities? Probably. It isn't, you have to get a bit into the forecasting business and some of the people who develop projects are really not very deeply, deeply capitalized. And historically, that's, that's been the way that the, that the market grew. It was just kind of moms and pops who came out of some utility affiliates and were, and were, were building projects.

So I think it's just historical, effectively, and sure, you could do it. It'd, it'd be a conversion, and I'm not sure that any developer would necessarily be better positioned than the utility to assume the risk of cost price fluctuation. And maybe the utilities wouldn't even want to give that up, I don't know. It's, it's a good question for PG&E.

MR. WAN: I can try to answer that question. I think there's a couple of things going on. If the project is actually a baseload project, then it becomes fairly easy for either party to hedge the fuel price risk. And then it does become whose balance sheet is strong and whose cost of capital is lower. And I would say that in that situation, it's probably cheaper for the utilities to do it.

However, most of the gas, gas-fired plants are not baseload. If you look at PG&E's service territory, during the summer, the middle of the night our load is less than half of what it is over the peak of the day. So what we're doing is really that we want to buy tolling rights for the ability to dispatch, even it's over the peak of the day, and then try to bring them down to minimum or even shut them off in the middle of the night, and we put up all these resources in our least cost dispatch order. And that would make it almost impossible for any of the sellers to predict when the load would be, how we would use them, and then be able to procure fuel supply or hedge the risk to correspond to that. So it depends on the situation.

MR. GHOSH: Our answer would be slightly different, from our experience. We found that, that the utility level is cheaper, and it's cheaper because of the same portfolio effect we talked about before. The utility hedges out their net exposure. That net exposure is a combination of a lot of different fuels, a lot of different base versus peaker facilities, and that net exposure hedge is often much smaller than 12 different power producers hedging it out independently.

PANEL 2 MODERATOR ACKERMAN: That sounds like you're hedging the fuel adjustment or something like that, if you're taking the whole portfolio of utility projects. Is that right? Okay.

Lad, do you have any comments for John or Russell, or questions?

MR. LORENZ: I think the only, the only question that I have is assume for the moment that, that the utility would be interested in ownership of renewable projects. Would you guys be a potential source of, of financing options for those kind of special entity --

PANEL 2 MODERATOR ACKERMAN: In other words, there would be a build-on transfer, and then you're asking them would they be interested in putting skin on that game. Let's go to Russell, then we'll go to John.

MR. READ: The answer is yes. Okay, it's more than that, but it, it's, you know, it's absolutely yes. The idea is that, you know, we're looking for -- you know, in many ways we're natural partners, you know, with a number of utilities, you know, our interest is finding, you know, is being able to, to, you know, find the profitable areas in the, in this capital market sector, you know, that it makes sense from a number of, from a number of perspectives. It does include, you know, private equity, public equity, fixed income, and real estate investments.

So this is a, it's something which, from our standpoint, you know, has a lot of life to it, particularly, you know, sort of given new, new realities of the needs and opportunities in that sector. We sort of see this as, you know, the -- give you an example of some of the things that we're looking at and some of the changes that we're seeing.

You know, essentially from 1980 through at least 2002, there were, you know, about no IPOs, about zero IPOs in the energy and material sectors. We're expecting about 50 percent of the IPO activity over the next ten years to be in the energy and material sectors. So in terms of new economic activity, this is a, this a major opportunity for us, and it's, it's one that's, you know, I want to highlight something different, too.

You know, in, there was a lesson, I think probably the wrong lesson, that was learned as capital markets investors from the period 1980 through 2000. And the lesson at that time was, you know, invest in the capital markets. The markets themselves, you know, will sort of, if you're invested in, let's say the S&P 500, that was, that was the major thing that you wanted, wanted to do. The worst thing was not to be invested. You had the wind at your back, though. You had interest rates declining, you had, you know, most sectors of the economy doing well.

But the period in 1964 to 1980 was very different, you know. We hit a, a level of about 980 on, on the Dow in 1964. We broke a thousand in 1980, so 16 years of flat. During that period, you know, of 1964 to 1980, you had a different fundamental lesson in investing. It wasn't that you could simply rely on the capital markets, you actually had to go hunting. You had to find the opportunities. It wasn't that there weren't opportunities, but you had to find it.

And I think conceptually, we're much more in a mindset like that today, and over the next ten years, than we are, than we were in the period 1964 to, to the year 2000. We want to go, you know, searching out and hunting for those opportunities. And frankly, this is a particularly important sector, so I think our, our ability and interest in working, for instance, with utilities on, on alternative and renewable projects is very high.

And, you know, it's something where, frankly, we know that the costs of capital for a number of these projects are very high. Just to get scale, you know, how much is a, how much is a new O&G terminal, you know. Is it $10 billion a pop, you know. How, how about, how about an ethanol plant, both in the sourcing of material as well as getting scale efficiencies for producing the ethanol. We know, we know that costs are high, and frankly, we're, you know, we'll be an important source of capital to, to achieve that scale, so.

PANEL 2 MODERATOR ACKERMAN: Okay. We go to John, and get an answer for --

MR. BUEHLER: That's a terrific

question. The short answer, yes, for wind projects, because we're pretty inefficient with tax benefits anyway, so build on transfer would be one of the preferred models for doing wind financing. And no, for virtually everything else for reasons kind of indigenous to the nature of a private equity beast. We have, generally speaking, generically five-year investment periods and ten-year terms, and you, within the five-year investment period may or may not be able to re-deploy capital which has been returned to you, as opposed to operating capital.

And that obviously has a pretty dramatic impact on the multiple of capital that your investors get back, so our investors, including CalPERS, would not want us to take that kind of risk, by and large.

On the other hand, we have had several European funds where the build-on transfer model was much more generic to their infrastructure than it is here in the United States, and we have been involved in build-on transfer structures but those were funds which were specifically oriented toward, toward that kind of model.

So re-deployment risk and, and longer is better, and that's, that's kind of what our investors are expecting. They're expecting kind of 20, 20 percent returns over a ten-year period, not kind of highly intense IRRs over a two-year period.

PANEL 2 MODERATOR ACKERMAN: Okay. Pedro, you're the only guy standing between us and the break. What comments or questions do you have?

MR. PIZARRO: Well, that's a loaded way of putting it. Maybe I'll just let us go to break.

PANEL 2 MODERATOR ACKERMAN: Loaded? I'd say. You're going to pass? Okay.

Joe, what time should we all be back?

UNDERSECRETARY DESMOND: Ten minutes, 25 of, and then we'll quickly go into the last two.

PANEL 2 MODERATOR ACKERMAN: All right.

(Thereupon, a recess was taken.)

PANEL 2 MODERATOR ACKERMAN: Let me get, let me get real here. Had my slides worked as I had planned, I was going to mention something which I think the truth of which will be abundantly obvious. So before I introduce Curtis Kebler here, I just wanted to say -- there we go.

Well, let's go back. Come on. Great keys you have here. There we go.

I think as you can appreciate now that you've heard several of these top-notch presentations that oftentimes you come to a workshop or a conference like this and you expect to get spoon-fed, right; that we're going to give you all the answers and you're going to go home, you say I went to a conference and I forgot what everybody said.

Today, though, on the other hand, spoon-feeding won't be the order of the day. I think it's more along the lines that you're going to have to put some thought to key together some of the points that people are making here, and that makes this very different in terms of a typical presentation that, or workshop, or any kind of conference you might otherwise enjoy.

Let me get Curtis' slides up here and introduce him to you. Here we go. I'm getting really good at this. Can I get a job here?

(Laughter.)

PANEL 2 MODERATOR ACKERMAN: All right. Curtis is -- I hear with your company I would have to fail an entrance exam to get in.

(Laughter.)

PANEL 2 MODERATOR ACKERMAN: You guys ordered twice for lunch.

All right. So here we are. Curtis Kebler is a Vice-President of the U.S. Power Trading Group at Goldman Sachs, and he's responsible for a broad range of technical and policy issues before various organizations in the western U.S. Also worked once upon a time at Reliant Energy, Southern California Edison, and the Power Exchange.

So put your hands together and welcome Curtis Kebler.

(Applause.)

MR. KEBLER: Okay. Well, thank you very much. I know it's getting late in the day and everybody's anxious to wrap this thing up, so I'll be rather brief.

What I'm going to talk about are more sort of the whole topic of, of credit and risk. I'm going to talk about it from a, sort of a transactional, a structure perspective, and how, how different structures can be designed to address some of the issues that we've talked about today. And the context for my remarks here are,

are really some, some discussions that are going on at the CPUC right now that deal with issues like resource adequacy and how do we ensure that there are enough generation resources to meet the, the needs of our consumers reliably while ensuring that the costs of those resources are, are allocated to everybody who, who benefits from the resources.

So in the course of the discussions that have been going on at the PUC, some, some different models have been introduced to deal with these, these issues like resource adequacy, and so forth, and so what I'm going to do, I think some of these, these models may have application to renewables projects and to the general issue of risk that we've talked about today, and credit and so forth.

So what I'll do is I've got, I've got really three models that I'm going to walk through, and I'm not going to go into any details on these, just, just give you a high level sense for what they are. All three of these have been discussed at the CPUC in, in recent months, and, and then conclude with just some observations about this notion of, of transaction structure and how it may be able to address some of the concerns that are the subject of this workshop.

This first mechanism here, and again, this is, this is in the context of a, of a proceeding that's intended to figure out how can the utilities, if they determine that there is a need for new generation and there are certain parts of the industry that aren't, aren't in a position to enter into the kinds of long-term contracts that would get new generation built, how can we actually build new generation, provide the long-term contracts necessary to get, to get financing, and then allocate the costs appropriately.

And, and this was the proposal put forward by a group called, that refer to themselves as the Joint Parties, and it consisted of Southern California Edison, PG&E, a couple of generators, NRG and AES, and then also the consumer group, TURN. And, and this is a pretty basic structure. It looks sort of like the QF contract model where you have the utility in the middle, and then on the left side this Buildco entity, which is just a term we, we use just so it fits with the, the other two models you'll be seeing.

So there's a Buildco, and the utility enters into a long-term, say a ten-year contract, with this, with this renewables developer, say, or a conventional project, and so they get a certain dollars per kilowatt month over a ten-year period. And what's, what's unique about this proposal that was put forward by the joint parties is that the resulting cost of that ten-year contract would be allocated to all customers in the service area of that particular utility.

So if it were Southern California Edison, for example, and it had a need for a thousand megawatts, or some amount, and it was decided that this mechanism would be relied on, Edison would conduct an RFO, the winning bidders to a thousand megawatts would be selected. The total cost of that project would be allocated to all customers connected to the Edison distribution system, whether or not those customers got their commodity supply from Edison. So if, if there were retail energy service providers or, or other classes of, of load-serving entities, they, too, would be allocated a portion of these costs.

And then this top line across, across

the top, you'll see it says RA value, and then net revenue from spot sales. The idea would be that the utility would take these, these projects that make up the thousand megawatts and they would essentially take those contracts, or the assets associated with them, include them in the utility portfolio, dispatch them in the market each day according to least cost dispatch principles, and to the extent that there were net revenues from those transactions in the daily spot markets, then those net revenues would be credited back to all customers as an offset to the total cost that they were allocated in the first place.

I hope that doesn't sound too, too convoluted. It's essentially a standard QF construct, but in this case the costs are being allocated to all, to all customers connected to the, to the utility distribution system. So that was the starting proposal in this, in this PUC dialogue.

A group of parties, including -- well, I work for Goldman Sachs, and there was, and I'm with the, the U.S. Power Trading Group, which is really Jay Ahren is the trading unit at Goldman Sachs, and we had some discussions with other stakeholders in this process, and we identified an alternative model that we put forward. And here we, we've called it Investco. And, and Investco is, is a modification to the structure that we just looked at, and essentially what it provides for is an intermediary entity called Investco. It could be an investment bank, it could be, it could be one of the, the high credit quality generating companies. It could be a variety, it could be hedge funds, it could be a number of entities.

The Investco would enter into a, say, a ten-year contract with Buildco, and Investco would turn around and essentially negotiate the, the terms and conditions of this ten-year contract, turn around and offer that project into a utility sponsored RFO. And the, sort of the, the key element about this, this particular structure is what the Investco would do in offering this, this product to the utility. It would, it would essentially separate the energy component of the new resource from the, sort of the resource adequacy component.

So if you, if you think of the total cost of the project being X dollars per kilowatt month, Investco would say to itself it can assume a certain amount of energy risk for ten years. So of the total project cost, which the, the Buildco is assured of getting, Investco assures Buildco he, he's going to have a ten-year contract at X dollars a kilowatt month, Buildco can then go off and build against that and get its project financed. Investco would say of that total, this portion is really the energy value of the project. We, Investco, will take on, take on that energy risk and be responsible for capturing those revenues out of the wholesale market.

The difference is then they'll with, as sort of an uplift charge to the market, and what would happen is the resource adequacy piece, that's the, the RA, is flowed through to the, to all customers again, just as in the joint parties' proposal.

So in this case, all the customers are receiving ten years of resource adequacy value, and, and then purchases of energy are the responsibility of the individual load-serving entity. So the value or the benefit of this structure is if you're a customer and your load-serving entity is fully meeting your energy needs, and there is some mechanism out there where the regulators say we need to go out and we need to build new generation, and we need to allocate costs to all, all customers in the system, or all customers connected to this particular utility system, what this structure says is okay, we're going to limit that allocation, that socialization, to just the RA piece, and then the energy component, the energy value is borne entirely by Investco.

The other sort of salient feature of this is, is that the Investco is facing off against the utility. So the Investco is a, is a high credit quality entity. It faces off with the utility in terms of credit, and then Investco in turn is facing off against Buildco, and all of the credit risks and all the operational and development risks that we talked about earlier are managed in, in the interface between Investco and Buildco.

The, once this model was introduced and discussed in the PUC environment, one of the issues that came up was that the, the Investco is really, in this, in this approach, is essentially taking on ten years of energy price risk. And there's some concern that given the nature of the market today and, and where the, where -- the maturity of it, and so forth, that there might not be that many entities that could step up and take on a ten-year energy position. So there's, there is a few, but there might not be that many entities. Maybe a few of the banks.

But then in addition, even if there were a few of these entities, given the uncertainty and the newness of this, of this idea, there might be some large premiums built in to the, to the energy component which would effectively lower the, the value that Investco was placing on the energy increasing the RA component, and so that was a concern that some parties had.

We, we, in the course of this whole process at the PUC, modified the Investco structure to this last model that you're seeing, which is called, we've called Distco. This is very similar to Investco, with the distinction being that rather than Investco doing sort of a one-stop auction where it, it provides an RA offer to the utility and takes on the energy risk, and that occurs essentially simultaneously in one, one transaction, the Distco model essentially breaks it into two transactions. And it says the utility will be the entity that enters into the ten-year contract to get the, to get Buildco to build the project.

So Buildco knows it's got a ten-year contract with the utility, it's assured of that revenue stream, it can go get financing. But then the requirement is that that project, that the energy value associated with that new project be auctioned off and that all buyers and sellers in the market have an opportunity to seek to acquire the energy rights to this particular plant, and -- or, or a group of plants.

And the idea is you can -- and this is sort of in the lower right portion here -- you can structure the energy auction so that you're, you're reducing the, the tenor of the, of the commitment. So you could, you could do a five-year energy auction, say, or even a two-year or a three-year energy auction, and by having a shorter energy commitment period where the, the buyer is committing to a fixed price for energy that's a shorter term, the idea is you'll get more participants, there'll be less risk premium.

And in the end, the way this was proposed to the, to the CPUC, is that if we conduct, if the auction were conducted and the regulators were to look at the results and say we just don't think there's enough energy value in these offers that we've gotten in this process, then they could essentially default back to the joint parties' proposal for say a period of one year, where, where essentially the utility would put the unit in its portfolio, dispatch it at spot prices, that would go on for a year. The auction would be re-run, and if in that case the, the results were considered satisfactory, then the results would take effect.

So the upshot of this is that there, as a result of this need to address resource adequacy and come up with hopefully some creative ideas to addressing resource adequacy and allocating the cost fairly to all customers who benefit. Some different structural have, have been put forward, and these are variations on, on the traditional QF model. And our thought is that in, in thinking about some of the issues, and this is my last slide, thinking about some of the issues that are, that are facing the renewables community, our thought was that some of these, some of these sort of intermediary structures, particularly Investco, might be something that would be suitable for, for the renewables area.

And so the bottom line, credit quality is the subject of the day. It's obviously the key to, to getting low cost capital. Some of the conventional utility RFO structures and mechanisms may have certain limitations on them, and we talked earlier about the issue of step-in rights and how difficult it is to create standardized step-in rights so that if you're the utility and you've got, as Fong said, you've got 50 respondents and you've, and you've got, you've got to evaluate them all fairly, it's very difficult for the utility to go out and negotiate step-in rights with individual projects unless it's got some kind of standard provision, which is certainly possible, that applies to everybody. And then, then that doesn't distort the, the evaluation process.

But the, the idea here is that there may be some restrictions. The intermediary structures that we've been talking about in the PUC proceeding, which are really focused at this point more on the conventional resources, there may be application of those kinds of intermediary structures to the renewables area going forward.

And those are my remarks, Gary.

PANEL 2 MODERATOR ACKERMAN: Okay. Our last speaker for this panel will be John Flory. And John is president of North American Energy Credit and Clearing Corporation. He was very instrumental in the development of the California restructuring, of the development of the Power Exchange and the ISO, which, so, of course, we know the California Power Exchange has had its life. Subsequently, he became Vice-President of Strategic Planning at the Power Exchange, and was key to the formation of spot markets, as well as first of their kind physical exchange based forward markets for electricity in the U.S.

So put your hands together and please welcome our last speaker, John Flory.

(Applause.)

MR. FLORY: Thank you all for staying awake for my last presentation.

NECC, North American Energy Credit and Clearing, started in 2003. George Fidoji and I got together to kick it off. But as hinted at in Gary's comments, the genesis of it was actually at the Cal PX in 1999. George Fidoji came from the

Chicago Board of Trade, and when he got to -- he was the number two guy there for about a decade. When he got to California he said this is an interesting way to run a railroad. He says there's an awful lot of risk in the marketplace here, and there's some things that we think we may want to do to try to change things. One of those was the introduction of forward contracts, which we worked on and achieved.

The other was putting together something that looked more like a physical clearing house. And in that case, we were building the ark, but the floods got there before the ark got built. When George and I got back together again in 2003, we said, going to Pedro's example of earlier, in, before 2001, there was all that credit risk there that no one has managed it well, and now the pendulum is going the other way, and now people are really collaterizing the credit risk. And we, there's, we saw some efficiencies that could be brought to the market from a risk management and capital perspective. And that's what we set out to do.

We have as our strategic partners ICE, the Inter-Continental Exchange, the largest electronic broker in the energy space. The Clearing Corporation is an 80-year old independent clearing house that used to be associated with the Chicago Board of Trade. Credit Suisse, who has helped us on some backstops, and, and some of the securities -- securitization type products to backstop that.

And just as some, some background. The -- there we go. Just for those of you who aren't familiar with the clearing house concept, most transactions are over the counter transactions. You have two parties, like A and B, who deal with each other and face each other's credit. But often there's more than two counterparties in our marketplace, and so you have all these different potential credit lines and credit facilities between entities. The advantage of a clearing house, it allows you to focus on what people's net positions and net exposures are, and there's some real risk management and collateral efficiencies from having a clearing house type solution.

And some, some analysis done by the Committee of Chief Risk Officers of some power and gas entities showed some potential 80 percent reductions through netting down to what people's really net positions are in terms of the amount of collateral to be posted.

And we've looked around at this clearing house model. We thought that was a good core, but a lot of them were financially based. And we decided we need to have one that needed to be a physically based clearing house. And we looked around and the Natural Gas Exchange in Canada and NorPool in Scandinavia seemed to be the -- the Natural Gas Exchange for gas and NorPool for power, seemed to be the two best prototype models to start with, and so we went about trying to adapt a clearing, physical clearing solution to the U.S. markets building upon the lessons learned elsewhere.

And we are a physical counterparty as a result of that. We signed EEIs and NASBEs, the type of docs that Fong referred to earlier, and we also arranged for backstops so that -- because we are, we are responsible for the physical delivery, not just the financial settlements of risk.

And one of the things that really differentiates by being a physical clearing house is that most of the financial clearing houses work with just mark-to-market, what we call the tip of the iceberg of risk, so that if you have a marketed transaction that's purchased at 70 it's good, the 75 you've got a $5 mark-to-market risk. But as that rolls to delivery, you have the full $75 of risk as a receivable to, to be managed.

And one of the other things that this does, and listening to the conversations here today, is by us focusing on the full iceberg of risk we, we have some opportunities to potentially look at models beyond just the mark-to-market way of, of managing risk that, that seems to be a bit of a challenge here for putting the renewables on a, a level playing field, or, or a better playing field.

And so, and what we have done is, is to put together a clearing house that combines the traditional advantage of the clearing house in terms of a single central counterparty with all positions secured and additional layers of protection, and insurance and, and using credit derivatives markets and things like that. But we, we've bound this together in a, in a physical transaction so that this capital and credit risk can be managed all the way from a forward transaction through delivery and settlement.

And so this allows greater protection from a overall risk perspective, it allows max, greater netting of collateral requirements based on positions, and I'll have an example for non-renewable and renewable in a second, across different fuels, and also your pre-delivery position and your post-delivery position, the tip of the iceberg versus the base of the iceberg, as well as your netting across multiple counterparties.

And the other thing that I've heard a number of people have told us as we've been putting this together is they also see this as enhancing physical reliability because it allows the developers to put their dollars to work in putting steel in the ground rather than going to capital for collateral requirements. And the other thing, as the physical entity ourselves, if a supplier defaults we have, we make arrangements to have backstop suppliers, similar to what Partho had talked about earlier, to make sure that the buyer on the other side gets the electrons or natural gas to meet, to meet their needs.

So just one simple example in terms of collateral requirements. We have two, two generators, one's a natural gas generator and one's a renewable generator, with and without physical clearing. You, you can see the gas generator in this case had about $100 million accounts receivable, plus about $100 million of mark-to-market. They're able to drop because they can net their power sales against their gas purchases, and because you have the offsetting positions of, of gas and power moving somewhat together, you can hugely reduce the margin requirements for the gas generators.

Similarly, for renewable generators, because they don't have fuel purchases but they do have a huge chunk of the accounts receivable, the base of the iceberg that we talked about, and so there's opportunity for them to use that as a way to offset what their otherwise margin requirements or collateral requirements would be and significantly reduce the amount of capital. And, of course, by reducing the amount of capital, as we heard, that can potentially significantly reduce the, the cost or prices of power to Californians.

So thank you very much, and we'll talk if there are any questions.

PANEL 2 MODERATOR ACKERMAN: Okay. Let's go to our panelists here and see -- our, our commenters, I should say, and see what questions they might have for our presenters. Lad, Pedro, which one of you would like to kick off? Lad? Okay.

MR. LORENZ: The only, I only have I guess one comment, and that is that Curtis, I was pleased to see that the joint parties have modified their proposal, it appears you've modified the proposal to address SDG&E's biggest concern, that is that the allocation that would occur in any of those models to the, to the DISTCO would be done by a service territory as opposed to a market area allocation, so that even in the case of SDG&E that's fully resourced, we wouldn't see any of those costs, necessarily see any of those costs being allocated to us. So, you know, I'm, I was glad to see that, that clarification.

MR. PIZARRO: Yeah. And just to, to clarify the clarification, Lad, that, that has been, that has been the joint parties' proposal all along. The, Edison had its own proposal a year and a half ago, but we were looking at issues on a market basis, so I think there, there's a broad market issue there. But we, the joint parties' proposal acknowledges that the PUC can manage this on a service territory by service territory basis under AB 380. So that's been a joint parties' proposal all along.

PANEL 2 MODERATOR ACKERMAN: Follow-up questions, Pedro, to either of the speakers?

MR. PIZARRO: Yeah, I have a couple of comments. First of all, you know, thanks to both of you for the presentations. And one over-arching comment that I think goes back to this morning's discussion is, and I, for one, and I think Edison, and probably speak for the other utilities, too, would welcome a deeper and a larger role by intermediaries who can better manage the financial risk or even some of the physical risk.

So, you know, take my, my next couple of comments in that light, that I think anything that can take some of the risk management activities and put them with folks whose entire business system is about risk management, that's a good thing. And it's, you know, getting people aligned with their natural, natural ownership, you know, given, given their skill sets.

Curtis, a couple of things on, on your presentation, which I thought did a good job of outlining kind of the progression of, of different proposals of the PUC. First of all, one thing that was interesting is that when you think about all the various risks that are being managed here, again, connecting this morning's discussion with this afternoon, you have development risks, you have operating performance risks, you have default risks, you have bankruptcy risks. Then you also have the load migrations, stranded costs, retail market kind of risk.

I just wanted to point out that from, to some extent, from a joint parties' perspective, the joint parties' proposal really was about the last of those in that the cost allocation mechanism is all about how do you make sure that on a service territory basis you get, as you acknowledged, all parties contributing equally to, to making sure that new generation is being developed.

I don't think the joint parties' proposal nor the other proposals necessarily do a whole lot about the prior sets of risks, although, depending on whether you have an Investco or the like, and you may have entities that can manage those risks in a different way. Which leads to my next comment, which is, and I think I said this to you before, we would welcome to see an Investco step up in our RFO, and assuming that the PUC adopts something along the lines of their PD in this, the all party meeting tomorrow around this, assuming they do that and we go out to the market with our RFO, we would be thrilled to see Goldman Sachs come in and say in the Investco model, you know, you'll go ahead, you'll, you'll take really the, the energy offtake risk, you'll basically price a capacity product for us on a ten-year basis, and we'll deal with capacity only contract.

In fact, we would've been thrilled to have seen that in our last solicitations, you know, in the five-year old source. We haven't seen that yet. I hope that at some point the markets will mature sufficiently to get us there. So a long way of saying we, we'd welcome that, and I don't think we need any action from the PUC to make that happen. I think it's just a counterparty showing up at our RFO and saying Edison, you solicited a bundled product or tolling products, but, you know, here is an alternative product, at least, and I think we'd be very open to looking at that. Maybe they will send the details and, and, also to that.

And then the final comment I'd like to make, and it goes to both the Distco model and the, and the PD that was issued, which is I think very close or largely along the lines of the Distco model, is first of all, you know, I think that the model has merit to it. Again, as we've discussed in the past, a key thing from a utility perspective is going to be that we do have the flexibility to, if we go down this auction path, that we be able to see what bids come back and whether or not they're attractive.

So, so we wouldn't want, and I know, I don't think you're proposing that we would have to auction, but rather, that we would offer up for auction, get bids, evaluate those, and if they present a better package, then we can accept this.

Secondly, I think there are a lot of devils in the details in terms of the whole process for making that selection if we, you know, if we run that auction. I'll give you one example, and just one example, that, that we struggled with as we were developing the proposal.

How do you appropriately balance the need, a legitimate need for transparency that all LLCs would have to that process, with the fact that if it's a utility running the evaluation and the selection there's confidentiality issues that the PUC is weighing in their confidentiality OIR right now. At the end of the day, we admit of not being smart enough to figure out a way to do all that, provide sufficient transparency, and so that's why we defaulted in the joint parties proposal to crediting all LLCs with the financial value of energy on a spot basis.

And what we figured was that mathematically you get to the same place anyway, because now you're giving individual LSEs who are getting this allocation a choice. They know they're getting an allocation of essentially a financial index product, right, because you're telling them we're going to place in your hands the financial value of spot energy sales, or whatever spot is, it looks a lot like an index product. An individual LLC can then make the choice of do they take those revenues and on the same day buy energy at spot with those and basically not have a gap there, do they choose to layer on a hedging product, a swap or some other vehicle, to transform that index allocation into more of a fixed obligation, or a fixed, fixed product.

So we, we think that mathematically you'll probably get there because individuals could layer on forward hedges themselves without as much of a complication, but, but we're open, and I, I know this will be a subject of discussion at the PUC.

Sorry, a little long there, but --

PANEL 2 MODERATOR ACKERMAN: Do you want to counter, Curtis, any of that?

MR. KEBLER: No, I don't, don't want to counter. I, I think it's, it's very good to hear that at least one of the utilities has -- I think it's very, very good to hear that at least one of the utilities are interested in, in exploring the Investco model.

I guess one question would be when, when you indicate that the, in an upcoming RFO, that you, you would actually like to see people respond and offer that kind of structure, do you think that is consistent with the way the PD is drafted, which seems to be more in the direction of the

DistCo type model. Are, or are you talking about
two different RFOs?

MR. PIZARRO: No, I'm, I'm talking about
the same one, and I think you're raising a good
question. The, and I'd say it even a little
differently. I think the way the PD is drafted
it, it's telling us to go out and solicit
contracts for new build. And I think the
implication is that those probably look a lot like
tolling contract, or, I think that potentially
this would probably be tolling contracts. And it
then layers on the possibility of DistCo and it
says that utilities go off and figure out some
proposals to be considered in a long-term
procurement proceeding.

My point, Curtis, was that I don't think
there's anything in there that would stop somebody
who wanted to be an investor and who just wanted
to sell a capacity product from a certified new
plant, I don't think there's anything stopping
them from placing a bid like that in an RFO. Now,
I, you know, subject to checking, and again,
devil's in the details and all that sort of stuff,
I think at one point we made comments where, you
know, we have this fast track and we have a

standard track, we do want to move very quickly with the fast track and the PUC has appropriately put a February deadline on when we come back with contracts.

So I don't know, depending on what an Investco bid looked like, I don't know if we'd be able to handle finishing a valuation on that timeline or whether we'd get pushed to a standard track. But I think, you know, it's, stepping way back, of course, we're absolutely open to the idea of financial intermediaries stepping in, creating different risk management approaches, and allowing us the opportunity to look at those relative to the, you know, the other options we have, and, you know, making decisions and seeing if the PUC agrees.

So, I mean, I'd be very intrigued. Again, I just haven't seen it, there's been talk about it. It's promising. We've heard some great things today. But just be real honest with you, I have not seen such a bid show up in our doorstep yet.

MR. KEBLER: Yeah, and I, and I think part of it may just be a little bit of a lack of a, sort of a, a framework for us to evaluate and,

and not having a clear sense of what, what did the regulators think about this kind of model. So it's, it's very encouraging for the utilities to indicate that, that they are interested in this model, and the regulators have said they support the DistCo approach released in the Strapp decision. And if they're also receptive or nothing precludes an InvestCo type offer, then I think that's very positive, and, and we'll look forward to having these additional discussions and getting more into the details and, and seeing if it's a, a truly viable investment structure.

MR. PIZARRO: And just quickly, I know, I know you were involved and other folks in this room have been involved in the working group on developing the capacity product. I think that can be an important milestone that would help facilitate something like the InvestCo model, right, because now you'd have better definition of what, about what it means to have a capacity product. And then I think that would help people bid that structure.

MR. LORENZ: Yeah, that, that was going to be my comment, is that the, the InvestCo, in the way you structured it, would be offering that capacity product, and so, you know, whether, whether it's the capacity market comes first and then this follows, or this facilitates the development of a capacity market, either way, that's where we want to get to.

MR. GRECO: I think, Curtis, just a question in, in that, because what I'm struggling with is, in this model, is how do you actually get new steel on the ground and how do you get it finance-able. That's what I struggle with as a developer. So maybe you can help me understand that a little bit more.

MR. KEBLER: The, the idea in the InvestCo model is that the, the BuildCo, the developer, would work with the InvestCo entity, and they would essentially agree on what's the cost to build this project, and, and would agree on a price. And if --

MR. PIZARRO: Would that be pre-bid, or, or post-bid?

MR. KEBLER: This, this -- this is sort of a simultaneous --

MR. PIZARRO: That's what I'm struggling with.

MR. KEBLER: This is sort of a

simultaneous process where the, the contract to the BuildCo is contingent upon acceptance of the offer in the utility RFO. So these are, these are sort of partnering arrangements between the InvestCo, which is the intermediary, and the developer. So they're essentially working together and, and that, so that's, that's how you get steel in the ground. The, the result of the successful selection in the utility RFO would be a ten-year contract for BuildCo that he could then go and finance against.

MR. PIZARRO: Well, hey, Curtis, check my simple mind in understanding here. I actually would rephrase what you just said. The result of the RFO would be a ten-year contract between the utility and InvestCo. Right? Because InvestCo would be, if I understand it right, InvestCo would be the counterparty with the utility.

PANEL 2 MODERATOR ACKERMAN: That;s true, for InvestCo.

MR. PIZARRO: That's what I'm trying to understand. Right?

MR. KEBLER: That's right. Right.

MR. PIZARRO: Right. Not BuildCo. Right, not BuildCo.

PANEL 2 MODERATOR ACKERMAN: Certainly not BuildCo, but I don't think --

MR. PIZARRO: Not BuildCo. And so, right.

PANEL 2 MODERATOR ACKERMAN: Not DistCo either. Not DistCo.

MR. PIZARRO: Right.

PANEL 2 MODERATOR ACKERMAN: Everybody following here? Snap your fingers when you get the teeth.

(Laughter.)

MR. PIZARRO: Tylenol will be distributed afterwards.

PANEL 2 MODERATOR ACKERMAN: Yeah, that's right. Well, go back, hold on. Let me go back to Joe. Joe, was your question answered?

MR. GRECO: Yeah. I think John had something to add.

MR. TORMEY: Yeah, I, I guess, trying to think about how you'd apply this in a, a renewables context. And, and it seems to me that, and I'd be interested in hearing from, from Pedro, your thoughts, or, or from Curtis, on whether or not that's a viable option right now in the absence of any kind of a REC market, or the ability to, to sell the renewable attributes separately. I mean, I think it's a really interesting idea to have intermediaries in the marketplace to, to, you know, allocate risk, but it seems to me that you really need to have a free-flowing market in all of the attributes that are being transferred in a, in a contract in order for that to work in that kind of a -- work with market intermediaries.

MR. PIZARRO: I think that's an excellent, excellent point. Maybe a little different take on, approaching it.

In the conventional generation example that Curtis walked through, there are really two attributes. One attribute is resource adequacy accounting, which some people call capacity, and we talk about a capacity product. But at the end of the day it's resource adequacy accountable capacity.

The second attribute is energy. There is a market for energy today. There isn't a market for resource adequacy capacity, not, not a big market like you have for energy. That doesn't matter, because the utility would be looking to contract for that resource adequacy product, and so with conventional generation and capacity I think it's, that's probably the simplest part of the picture, right, because what we'd be looking for in that contract with InvestCo is we're going to pay you, InvestCo, X dollars a kW month for capacity, and you're going to guarantee to us that you're going to keep online, you know, Y megawatts with a, you know, a must offer obligation and all the other terms, you know, for resource adequacy.

Now, switch to your question on renewables. When we contract for renewables we don't, we want both the resource adequacy accounting and we want the renewable accounting. So it's different in that sense in that now we want two attributes out of that contract, not just one. So a long way of saying I'm not sure you need a REC market necessarily, because we'll want, we'd want all the RECs coming out of there, right? That's the whole purpose of doing renewables contracting. But it does raise the issue, then, of how do you apply this model, because now you'd have the, the leftover attribute would be if you could unbundle the renewable accountability from the straight energy, then I think that's where you go to this kind of model.

MR. TORMEY: Right, but I --

MR. PIZARRO: Which means that you don't need a REC market necessarily, you still need to be able to access the energy market, but I'm sure there's all sorts of devils in the details and applications, and now trying to account for this renewable accountability and, and getting it recognized, and all that.

MR. SEYMOUR: Right. And I think that the, by REC market, what I'm referring to is, is the ability to separate the, the energy from the renewable attribute.

PANEL 2 MODERATOR ACKERMAN: Right. Right, that would have a different implication, certainly, in the application of that model.

John Tormey, any comments or questions that you want to finish up with here?

MR. TORMEY: Just a couple of -- well, only one question on this, and then I also had a question for John.

PANEL 2 MODERATOR ACKERMAN: Yes.

MR. TORMEY: I guess that, and it's more of a concern, and it is the one that you already talked about, which is I'm, I'm not familiar with, so it's too many so-called InvestCos, be they banks, marketers, or anybody else who has been willing to enter into a ten-year contract. And I think that's sort of the crux of the problem. I mean, I, most of the, the folks here who want to develop plants need a long-term contract to get the kind of project financing they want, and quite honestly, I, I think also, with respect to the price of, of the power, it's going to be one of the, the bigger parts of this whole process.

It's probably cheaper if we can get a longer term contract with the now investment grade utilities and our cost of money is going to be somewhat less than some of the shorter term contracts that may or may not have been done with, for example, Term 1B type financing.

PANEL 2 MODERATOR ACKERMAN: So you're favorable to the DistCo model instead of the InvestCo. That's exactly what you just said.

MR. TORMEY: It's a concern, I guess, and, and a question to, to Curtis.

PANEL 2 MODERATOR ACKERMAN: Well, I just answered it for you, so. But you had -- okay, Curtis, do you want to respond?

MR. KEBLER: Well, I think it's a legitimate question, and I think that, you know, we, we really haven't seen this type of structure yet. And so once we get a little more clarity around the rules, and the regulators have done -- are in the process of going in this direction, so I think it's, we're making progress.

In part, I think it depends on the kinds of technologies that we're talking about. I, I think doing, doing ten-year energy hedges on, on baseload type resources is, is an easier thing to do than it is for a peaker. And so in part, you may see the InvestCo model working better for particular types of technologies, and perhaps less so for peakers, until we, until we get better forward price information on, on other kinds of technologies.

PANEL 2 MODERATOR ACKERMAN: Okay. Back to you, John.

MR. TORMEY: Just a, a question, I guess, with respect to some of the other markets that may not have something exactly like this but rely on, on InvestCos to, to basically then contract back to back to get stuff built. Pennsylvania or, or Jersey, or any of the New England markets, I guess, can you, I'm asking, do you know whether or not contracts of that tenor

have been entered into into those markets to try
and get generation built?
MR. KEBLER: I can say that, without
getting into any specific things, I can say that,
that we are talking with a number and, a number of
different counterparties about baseload type
projects that would be financed off of long-term
commodity hedges.
PANEL 2 MODERATOR ACKERMAN: Okay.
MR. TORMEY: Yeah. Have any been signed
yet, though, or --
MR. PIZARRO: As far as you know, it
seems like this is an evolving area. It's not one
where you can point to example for --
PANEL 2 MODERATOR ACKERMAN: Okay.
Well, I'm going to have to -- sorry, you had a
question for John Flory, and then I'm going to
have to wrap this up.
MR. TORMEY: I do have --
PANEL 2 MODERATOR ACKERMAN: Please.
MR. TORMEY: I guess just whether or not
in the model we've been talking about where
somebody builds a, a single project financed
facility, you know, owned by an SPV, just because
I'm, I'm thick, I don't quite understand exactly

how the clearing-house works for --

MR. FLORY: In, in your, in the particular case of a one-on-one between, say, the, the SPE and the utility, that in isolation, assuming you get credit for your accounts receivable from the utility, it, there may be less opportunity for some savings. However, we do look at the opportunity for -- we set our margin based upon the opportunity for finding replacement suppliers, and so there -- and, and this, at the moment we, we've been focusing mostly on fossil fuel units at the moment, so I'm, I'm, this is a possibility, not a, a firm thing, is that there's a -- by setting ourselves up as a standard clearing-house doesn't make it easier to set up to, to find replacement suppliers of, of green, and I think the renewable energy credit discussion you had also applies here.

We, we, there's an efficiency in that process that potentially can allow the, the original margin, or the, the margin requirements or collateral requirements, to be lower than, than, than is often seen on standard bilateral transactions. And at the moment, just based upon experience and other markets, I can't actually confirm that, for renewables.

I will also say that we've had -- some people have talked to us about providing a type of a pooling situation, a clearing-house is a natural central place for a, for managing a pool risk or pool insurance type of thing. And so there's another way in which if you're trying to look at things from a portfolio basis and you're trying to have a, a mechanism that uses the diversity of risk in the state of California, as an example, then there's a, this would be an easy mechanism to adapt to, to try to facilitate such a, a pool risk management.

So those are sort of the, the two ways that I would see that the clearing-house model could potentially augment the bilateral, which is mostly bilateral relationship.

PANEL 2 MODERATOR ACKERMAN: Okay. I'm going to have to cut off the Q and A and turn it back over to Joe, but how about a round of applause for our presenters and our commenters today.

(Applause.)

PANEL 2 MODERATOR ACKERMAN: Okay, Joe. I'm checking out.

UNDERSECRETARY DESMOND: Actually, before you go, we've got a few more minutes. I actually was interested in hearing a little bit more from the generators' reaction to the clearing-house proposal. Most of that 15 minute discussion centered around the PUC, and since we're here to talk about credit risk and credit risk reductions and John's illustration was fairly significant in the example he showed, I was just looking to gauge a reaction before we wrap this up to see do people think that's worth exploring more in the interest of just a balanced conversation here.

PANEL 2 MODERATOR ACKERMAN: Let me go to John Seymour here. He has a comment for you.

MR. SEYMOUR: I guess the, the observation I have was as I looked at the, at the drawings we had on the clearing-house, that it looked to me that, that given the shape of the market we have for renewables in California, that the other word for that clearing-house in those drawings is the utility, because that's sort of the function they have. We don't have a market where, you know, John and I do deals and Joe and I do deals, and we all do deals with Pedro. You know, if we're doing a deal, we're doing a deal with Pedro, right, and he does a deal with John and he does a deal with me and he does a deal with Joe.

And, and so perhaps the ability, and this sort of ties back into something we discussed this morning briefly, I think, Commissioner, you, you had raised this as a question, is this perhaps something that at the end of the day is most efficient and, and lowest cost for the ratepayers if these costs are netted out by essentially the utility buying, buying a product, or the utility self-insuring for these exposures, rather than trying to put the collateral requirements on each individual generator.

And that just, it struck me that if you look at that diagram that the utility is in the role of the, of the clearing-house, and perhaps there's some efficiencies there if they looked at bringing that internal rather than on a single contract by contract basis. Just an observation.

PANEL 2 MODERATOR ACKERMAN: Okay. Anyone else?

I think we wore them down.

UNDERSECRETARY DESMOND: Okay. Well,

first, we have two more minutes to go here, so let me --

(Laughter.)

UNDERSECRETARY DESMOND: Let me start by thanking the panel. No more questions.

First, let me start by thanking the panel, both our first and second panel, as well as everyone who worked hard. Gary, I think you captured it correctly when this is not a typical workshop where we have a series of views that we know we'd like to see at the end of the day. This I think is really the start of, of a longer conversation that will occur over the coming months, and probably years, if our discussions on resource adequacy and capacity products are any indication about how long it takes us to move oftentimes in these new directions.

But having said that, I do think this is very, very useful, and certainly informative not only from my perspective but Commissioner Geesman, as well, and I can't speak for the other members of the panel. And my sense is that we're going to look back on this conversation here today six months, a year from now, and say this is, really was the start of a conversation about how we address this more, from the ratepayers' perspective, more intelligently, more efficiently, and in, in a fashion that moves us forward to achieving the renewable portfolio standard and also requirements for new generation to come into the state of California.

So with that, I would just note again, written comments will be due, I want to say the 12th I think is the date I had announced earlier in the morning. And as people submit them, we will be producing a workshop report. The workshop report is not just going to be a compilation of the transcript and the questions, but we're really looking to identify where do we go from here, whether it is relating the PPP concepts that were presented earlier in the securitization applying a clearing-house model, or whether it's to a single utility or all investor-owned utilities, collectively, as a way to of offsetting some of that risk. But the types of questions and exploration people would like to see where we go next.

This is not going to be a report that produces conclusions other than I think it's fair to say there are better ways to do this than we're doing it today. But with that, I think that will help give us some guidance as to the type of next steps, whether it's an additional, more detailed discussion, if it is something that the PUC can take up where you might think it's appropriate within the various proceedings they have either underway or something new is needed, and tying it back to that.

So again, I'll look forward to those written comments, and also thank the audience. As I said, this is a very specialized topic. Normally we have lots of folks interested, but I think we really had the people who needed to be here today, who understand the subject matter. Although it's a small audience, the decisions have far-reaching impact and implications, and offer the potential for hundreds of millions of dollars in savings to California consumers ultimately.

So with that, I'll ask if, John, if you wanted to add anything, or Eric.

CPUC COMMISSIONER BOHN: No, just I think it's been a very fruitful discussion in terms of getting, getting one's arms around this issue.

One, one of the lessons that I brought

back from my couple of days in the street last week was that the clarification that this kind of discussion produces is important in terms as, as we go forward. Predictability, expectation, all the things that people in the money business look for, you've got to kind of go through this process as a policy-maker to get there, and I found it extremely worthwhile, and I appreciate all your time and energy and thought that went into it.

MR. SALTMARSH: I also thought that, that this was a day extremely well spent. I had some, some perspectives moved forward to a new place by things that were said today. I think it's a very, very important topic, and it's one on which, you know, I would absolutely like to have insightful finishing comments, which I will entirely avoid trying to do because I don't think we're finished at all. And I welcome the opportunity to go from here to think about these things more until we come back again.

UNDERSECRETARY DESMOND: So with that, I'd like to thank everyone, and look forward to continued dialogue.

Have a great evening.

(Thereupon, the California Energy

Commission Electricity Committee Workshop on Lowering the Effective Cost of Capital for Generation Projects was concluded at 4:33 p.m.)

CERTIFICATE OF REPORTER

I, Christopher Loverro, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said Committee Workshop, or in any way interested in the outcome of said matter.

IN WITNESS WHEREOF, I have hereunto set my hand this 10th day of July, 2006.